72-438

FILED
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MICHAEL RODAK, JR.,

IN THE

United States Court of Appeals

FOR THE FIFTH CIRCUIT

No. 72-1114

On Petitions to Review Orders of the
Federal Power Commission

JOINT APPENDIX

~~(PART I)~~

OTHER SOUTHWEST AREA RATE CASE
SHELL OIL COMPANY, *et al.*,
Petitioners,

v.

FEDERAL POWER COMMISSION,
Respondent.

WILSON - EPES PRINTING CO., INC. - RE 7-6002 - WASHINGTON, D. C. 20001

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Superior Oil Company Application for Rehearing, received 11/26/71	R.12,297-12,308	523-534

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IN THE

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JOINT APPENDIX

(PART I)

OTHER SOUTHWEST AREA RATE CASE

SHELL OIL COMPANY, *et al.*,
Petitioners,

v.

FEDERAL POWER COMMISSION,
Respondent.

[10,911]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

Before Commissioners: Lee C. White, Chairman; L. J. O'Connor, Jr., Charles R. Ross, Carl E. Bagge, and John A. Carver, Jr.

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

ORDER INSTITUTING AREA RATE PROCEEDING

(Issued February 28, 1967)

On September 28, 1960, the Commission in its decision in the *Phillips* case (24 FPC 537), and its Statement of General Policy No. 61-1 (24 FPC 818, stated that it proposed to fix just and reasonable rates for independent producers of natural gas on an area basis. Since that time four area rate proceedings have been instituted. The Permian Basin proceeding (Docket No. AR61-1) has been decided by the Commission and a decision was rendered on appeal by the United States Court of Appeals for the Tenth Circuit on January 20, 1967, in which the Commission's decision was affirmed in part and remanded on certain issues.* The hearing in the Southern Louisiana proceeding (Docket No. AR61-2) has been concluded and the presiding examiner has rendered his in-

* The Commission intends to request the Solicitor General to seek Supreme Court review on behalf of the Commission.

termediate decision. The hearings in the Hugoton-Anadarko (Docket No. AR64-1) and the Texas Gulf Coast (Docket No. AR64-2) proceedings have also been concluded. These area proceedings will establish just and reasonable rates for about 79% of gas sales in interstate commerce, based on 1962 sales.

By this order we initiate a proceeding to determine just and reasonable rates for the Other Southwest Area described in Appendix A hereto. Sales in this area in 1962 accounted for approximately 14% of total sales in that year, so that upon conclusion of that proceeding

[10,912]

rates will have been established for about 93% of the natural gas sold in interstate commerce. The remaining 7% of sales which are in widely scattered areas will be treated separately from this proceeding.

The parties have had an opportunity in the current Hugoton-Anadarko and Texas Gulf Coast proceedings to present evidence directed not only to the principles enunciated in the Permian Basin decision but also to the questions raised in that decision on which other evidence was invited. Thus, presumably there exists in the record of these proceedings extensive evidence with respect to current gas costs, demand-supply conditions, reserve-production ratios, nation-wide flowing gas costs, allocation methods and other similar matters, much of such evidence substantially duplicating that presented in the Permian and Southern Louisiana records. No good reason exists for a re-trial or further duplication of this evidence in the proceeding being initiated by this order. Accordingly, the presiding examiner is directed to incorporate by reference all the evidence adduced in the

joint record in the Hugoton-Anadarko—Texas Gulf Coast proceedings (and may permit incorporation by reference to the Permian and Southern Louisiana proceedings) provided that specific portions of the joint record may be excluded upon a clear showing of irrelevance or immateriality. Evidence may be presented on any new issues not raised in the joint record and witnesses may supplement data presented or opinions expressed in the joint record but cumulative or repetitive direct evidence, cross-examination or rebuttal shall not be permitted. It is our intention that, absent new evidence, the same issues shall not again be tried in this proceeding but that non-repetitive testimony or cross-examination be allowed by any of the parties on new issues or respecting matters incorporated by reference. This would include theoretical concepts related to issues applicable to the instant areas. This proceeding essentially should require and be limited to new evidence respecting area conditions, area costs, and rate design.

The length of prior area rate proceedings has been a matter of concern to the Commission. These proceedings have imposed a heavy burden upon respondents and intervenors as well as upon the Commission staff. While we are aware that the institution of a new proceeding will require continued attention of the parties, we are confident that the experience gained in the past and pending proceedings will do much to expedite the hearings herein and lighten the burden of all parties concerned. The new procedures we are providing for should likewise serve this objective.

The basic data respecting area costs are obtainable from the All Areas Questionnaire issued by Commission letter order of October 30, 1963. At the request of a

number of Questionnaire respondents, however, the Commission, by orders issued January 9, 1964, and June 12, 1964,

[10,913]

indefinitely deferred the requirement to furnish certain data including that involving gathering and processing costs in the subject area. It is now appropriate that the gathering and processing data be furnished for the Other Southwest area and we are accordingly today terminating the deferral of the submission of such data. While we would normally require submission of questionnaire data within four months, we have extended the period to eight months in order that the parties may have the opportunity at the prehearing conference to consider stipulations or agreements as to gathering and processing costs to be utilized in the proceedings. If, after the initial prehearing conference, the presiding examiner reports to the Commission that agreement has been reached which may make it unnecessary to obtain the deferred data as required by the order referred to, the Commission will then reconsider the order. If no such agreement or other satisfactory disposition is reached, the respondents will proceed to furnish the data in accordance with the order.

To expedite the proceedings at the prehearing conference and the disposition of data requests, any parties interested in making data requests or in receiving copies of such requests made by others shall so advise the Secretary of the Commission within four weeks of the date of the order instituting this proceeding. The Secretary will then prepare a preliminary service list of such parties and this list will be available to all parties requesting the same.

[10,913]

Order Instituting Area Rate Proceeding

This proceeding, like the Permian and pending proceedings, will result in the establishment of just and reasonable rates under Sections 4(e) and 5(a) of the Act applicable to all persons making sales of gas in interstate commerce from the production areas delimited herein. These persons are listed in Appendix B attached hereto and are made respondents in this proceeding.

A number of pipeline companies make purchases in the producing areas covered by this proceeding. The Commission has recognized that pipeline purchasers are directly concerned with the determinations which the Commission makes in area rate proceedings (See 29 FPC 981, 983). The contracts which have heretofore or will hereafter be entered into by pipeline companies for the purchase of gas in this area are subject to examination and review by the Commission. Consequently it is appropriate that these pipeline purchasers be made respondents in this proceeding. In Appendix C are listed the pipelines making purchases in the area covered by this proceeding.

This proceeding will also establish the refunds, if any, which may be required under Section 4 of the Natural Gas Act, and all proceedings involving increased rate filings suspended by the Commission for sales in the area will be consolidated in this proceeding. A list of the pending proceedings is set forth in Appendix D hereto.

[10,914]

Three weeks prior to the initial prehearing conference all data requests shall be served on the parties on the preliminary service list. At the initial prehearing conference all proposals for stipulations as to gathering and

processing costs and all other requests for data previously made shall be considered and disposed of by the presiding examiner. At the initial and subsequent prehearing conferences which the presiding examiner may schedule, consideration should be given to the incorporations by reference herein required and such other matters as may be deemed relevant to expedite conclusion of this proceeding.

The Commission orders:

(A) A proceeding is hereby instituted pursuant to Sections 4, 5, 10, 14, 15 and 16 of the Natural Gas Act to determine the just and reasonable rate or rates for the sales of natural gas subject to the jurisdiction of the Commission produced in the geographical areas designated in Appendix A and public hearings shall be held in this proceeding as determined by the presiding examiner. All persons named in Appendix B hereto and all parties on whose behalf such persons have filed FPC gas rate schedules for sales in such areas are hereby made respondents herein.

(B) All pipeline purchasers named in Appendix C hereto are hereby made respondents herein.

(C) The proceeding hereinbefore instituted shall also encompass the investigation of facts, conditions, practices, or matters relating to the sale of natural gas produced in said geographical area to aid in the enforcement of the provisions of the Act or in prescribing rules and regulations thereunder, and shall also encompass issues as to whether any rate or charge demanded, observed, charged or collected by any natural gas company in connection with such sales is unjust, unreasonable, unduly discriminatory or preferential.

(D) The Section 4 proceedings listed in Appendix D are hereby consolidated for purposes of hearing with the proceeding herein instituted.

(E) Any person other than the respondents specifically named in Appendices B and C who desires to participate as intervenor in the hearings designated hereinabove ordered to be held, shall, on or before March 28, 1967, file a notice of intervention or petition to intervene with the Secretary of the Commission in accordance with Section 1.8 of the Commission's Rules of Practice and Procedure.

(F) All respondents or intervenors making data requests or wishing to have such requests served upon them shall so notify the Secretary of the Commission on or before March 28, 1967.

(G) A prehearing conference shall be held pursuant to the Commission's Rules of Practice and Procedure in a Hearing Room of the Commission at 441 G St., N. W., Washington, D. C., commencing at 10:00 a.m. June 28, 1967 before a hearing examiner designated to act as the presiding examiner in this proceeding for the purpose of but not limited to affording all interested persons an opportunity to be heard with respect to the procedures to be followed in expeditiously determining the issues to be tried in these proceedings. At the conclusion of the prehearing conference or as soon thereafter as may be feasible, the presiding examiner shall set the dates for the service of testimony and exhibits by the staff, parties, and interveners, and the date for commencement of the hearing and cross-examination.

(H) Howell Purdue, a duly qualified and appointed hearing examiner, or any officer or officers of the Commission designated by the chief hearing examiner for that purpose (See Delegation of Authority, 18 CFR 3.5(d), etc.) is designated to act as presiding examiner in this proceeding as of the date of the issuance of this order and is authorized and directed in so doing to exercise all of the functions and authority prescribed by the Administrative Procedure Act and the Commission's Rules of Practice and Procedure, including the holding of the above scheduled prehearing conference and such other prehearing conferences as he may deem advisable to expedite the proceeding herein.

(I) A copy of this order shall be published in the FEDERAL REGISTER and served upon each of the respondents set out in Appendices B and C and upon interested State Commissions as is provided for in Section 1.19 of the Commission's Rules of Practice and Procedure.

By the Commission. Commissioner Ross dissenting in part filed a separate statement appended hereto.

[SEAL]

JOSEPH H. GUTRIDE
Secretary

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APPENDIX B

RESPONDENTS TO THE AREA RATE PROCEEDING (OTHER SOUTHWEST AREA), DOCKET NOS. AR67-1, ET AL.

J. S. Abercrombie Mineral Company
Adams, N. L., Sr.
Alexander, C. W.
Alexander, E. B., Jr.
Allied Materials Corporation
Alston, Francis H.
Amax Petroleum Corporation
A'Mell Oil Properties
Amerada Petroleum Corporation
Americana Oil & Gas Properties of Texas, Inc.
American Exploration Development Corporation
American Petrofina, Inc.
American Petrofina Company of Texas
American Realty and Petroleum Corporation
American Trading and Production Corporation
Amigos Oil & Gas Ventures
Anadarko Production Company
An-Son Corporation
Anderson, Jacqueline
Anderson Petroleum
Andrewski, H. C.
Anisman, M., Trustee
Anisman, Morris
Apache Corporation
Apco Oil Corporation
Argo, M. M.
Arkla Exploration Company
Arrington, J. H.
Ascher, M.
Ashland Oil and Refining Company
Athens, E. J.
Atkins, Katherine Adger
Atlantic Richfield Company
Austral Oil Company, Inc.

B and A Pipe Line Company
Bailey, Virginia Mitchell
K. Baker, Receiver
Bander, Joe
Barker, Walter L.
Barnes, Earl E.
Barnwell Debardeleben Oil Company
Barnwell and Kinzler
Barnwell Inc.
Barnwell Production Company
Barrett, Charlotte Osborn
Basin Operating Company
Bass, Harry W.
Baton, J. W.
Thelma Bauerdorf and Constance Cartwright Trustees for George F. Bauerdorf, Deceased
Beacon Oil & Refining Company
Beall, Alton G.
Beard Oil Company
Beckett, C. M.
Behring's Production Company, Inc.
Belgram Oil Company, Inc.
Berry, Thomas E.

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Thomas N. Berry and Company
Biedenharn, Betty Osborn
Big Chief Drilling Company
Biggs, Robert A., Jr.
Biglane, D. A.
Blackburn Gasoline Plant
Blair, B. B.
Bodcaw Company
Bohnsack, Richard L.
Bond, Durbin
Bond Oil Corporation
Bond, Roland S.
Borden, S. P.
Boteler, R. H.
Boteler, R. T.
Bracken Oil Company
Brandenburg, R. P.
Breckenridge Gasoline Company

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Brian, C. A.
Bridewell, Billy
Brightwell, Donald
Briscoe, Powel
Powel Briscoe Inc
Briscoe, Roy E.
Bristol, R. A.
Brooks, Jesse M.
Brooks, Jesse M. & M. James Brooks
Zach Brooks Drilling Company
Brown, George R.
Brown, L. D. and Trant, Sam
Broyles, C. W.
Broyles, Harvey
Bryant, W. H.
Buckwalter, Charles F.
Burk Gas Corporation
Burk Royalty Company
Burnett, T. C. and Ruby C., Estate
Burnham, Joe M.
Burns, L. T., Estate
Burns, R. G.
Burns, R. H.
Burton, C. P.
Butler, J. R.

C. F. and H. Oil Company, Inc.
Caddo Pine Island Corporation
California Company, a Division of Chevron Oil Company, The
Inez Calmes Executrix of the Estate of Kermit W. Calmes, Deceased
Calto Oil Company
Calvert-Mid American Inc.
Cameron, A. A. d/b/a Cameron Oil Company
George E. Cameron Inc.
Canary, S. C.
Cararas, Jerome A.
Caraway, Reagan J.
Cargill, Robert
Carpenter, E. M.
Carter-Jones Drilling Company, Inc.
Car-Tex Producing Company
Caruthers, J. D.
Caruthers Operating Company, Inc.
Carver, Mrs. Helen d/b/a Anthony Oil Company
Casey, Carl
Caska Corporation
Cassard, A. R.
J. G. Catlett Company
Central Commercial Company
Central Oil Company
Champlin Petroleum Company
Chapman, Harry Allen
Chastain, M. B.
Chicago Mill & Lumber Company

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Chisholm, Alexander F.
A. F. Chisholm d/b/a The Brandon Company
Cities Service Company
Cities Service Oil Company
Citizens Bank of Hattiesburg, Mississippi
Claiborne Gasoline Company
Clark, Anson L.
Clark and Cowden
Clark, F. A.
Clay, Thomas W.
Cleary Petroleum Inc.
Cloud, Robert E.
Coastal States Gas Producing Company
Coats, Alton
Cochran, Phil K.
Coffield, H. H.
Cohen, Don
Coles, Marvin J.
Coles, Otis C., Jr.
Collins, George Fulton, Jr.
Colpitt, James R.
Columbian Fuel Corporation
Comegys, W. M., Jr.
Commercial Solvents Corporation
Compadre Oil Corporation
Consolidated Oil & Gas Inc. (Colo.)
Continental Oil Company

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Cook, Tom, Jr.
Cook, William H.
Corban, Charlie
Cotton, Doyle W., Jr.
Cotton Valley Community
Coulston Drilling Company
Coutant, A. E.
Cox, Edwin L.
Crescent Drilling Company, Inc.
Creslenn Oil Company
Crestmont Oil Company
Crest Petroleum Inc., Agent
Crichton, John H.
Criner Processing
Crockett, M. W. and Charles Kelly d/b/a Crockett & Kelly
Crow, Mrs. Cordelia K.
Crow, David, Trustee
Crow Drilling and Producing Company
Milton Crow Inc.
Crystal Oil & Land Company
Culpepper, Curtis
Curry, W. C.
Cuttychamp Oil & Gas Corporation
Cyprus Mines Corporation

Dal-Rock Production Company
Darby, Beulah K.
Daube, Olive H. d/b/a Daube Company
Davidor & Davidor, Inc.
Davis, C. D.
Davis, Paul R.
Davis, Waymon L.
Davon Drilling Company
Debardeleben, Charles F., Jr.
Dees, M. H.
Delaney, W. A., Jr.
Delhi Taylor Oil Corporation
Delta Drilling Company
Delta Gulf Drilling Company
Deposit Guarantee Bank & Trust Company
Despot, George J.
Dial, J. B.
Discovery Oil & Gas Company, Inc.

Dorchester Gas Production Company
Dorfman, Elizabeth F., Trust
Dorfman, Louis
Dorfman, Sam Y., Jr.
Draughn, Paul V., Jr.
Draughn, Paul V., Sr.
Dunbar, Blaine
N. V. Duncan Drilling Company
Estate of N. V. Duncan
Duncan, Walter
Dunford, O. D.
E. Dunlap, Jr. & State Oil Company

Eason Oil Company
Everett Eaves
Ward M. Edinger Inc.
Edwards, Robert J., Jr.
Elledge, Vernon and Hall
Ells, H. A. d/b-a All Star Gas Company
Elm Grove Gathering System Inc.
Erickson, E. L.
Evans, James P., Jr.

Fagadau, Sanford P.
Fair Oil Company
Fairfield Oil Company
Falcon Seaboard Drilling Company
Feazel, W. C., Estate
Felsenthal, S. J., Estate
Fender, Harris R.
Ferguson, Hershal C.
Ferguson Oil Company Inc.
Fields, Bert Estate
Fleet, Howard W.
Flesh, David J.
Florsheim, S. L.
Fohs, Julius F., Estate of
Fontaine, W. B.
Ford, Evon A.
Helen H. Feldman, Gertrude M. Reilly and Raymond J. Gertz, Trustees, Estate of Joseph Feldman

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Forest Oil Corporation
Forgey, R.
Forgotson, James M.
Foster, W. H.
Four States Drilling Company Inc.
Franks, John
Franks Petroleum
John N. Free d/b/a Free Lichty Drilling Company
Joseph F. Fritz
Fryer and Hanson Drilling Company

Gage, Coke L.
Gammill, Dave
Gant, Walter H.
Garrett, J. M.
Gas Rock Corporation
Gas Transmission Company
Genecov, A. S., Trustee
General American Oil Company of Texas
Genere Gas Industries Inc.
Geochemical Surveys
Geological Exploration Company
Gerhig Company of Arkansas
Gibbons, Ed
Gilbert, Arch B.
Gilmer Oil Company
Glassell, A. C.
Glassell, Alfred C., Jr.
Glassell and Glassell
Glen Rose Gasoline Company
Godfrey, Roy A.
Goins, J. I.

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Gose, Steve
Gragg Drilling Company
Graokla Gas Corporation
Graridge Corporation of Texas
Graves, A. R.
Graves, A. R. and Wetzel, Guy
Greenbaum, R. R. d/b/a Time Petroleum Company
Greenville Gasoline Company Inc.
Grigsby, Jack W.
Grimes, Otha H.
Gulf Mobile and Ohio R. R. Company
Gulf Natural Gas Corporation
Gulf Oil Corporation

H & H Oil & Gas Corporation
Hall, Frank J.
Hall, G. C.
Hall, Stanton A.
Hamill, Claud B.
Hamilton Gas Company
Hamman, Blake
Hamon, Jake L.
Hansbro, M. G.
Estate of M. G. Hansbro
Harden, Jack
Hardey, Charles O.
Hargrave, Horace C.
Harper Oil Company
Harris, James W.
Harrison, Wallace
Harvey, W. W. & Sojourner, W. C.
Hawkins, H. L. & H. L., Jr.
Hayes, Marshall A., Jr.
Heape, Gene
Hearnsberger, H. G.
The Hefner Company
Hefner, Robert A., Jr.
Heidelberg, Cecil F., Jr.
Roy Heidelberg II
Heldt, James D.
Helmerich and Payne Inc.
Henry, S. O., Jr.
Herold, Simon
Maxwell Herring Drilling Corporation
Hewell, W. A., Trustee
Hibbert, R. E., Agent
Hilburn, C. A.
Hinton, Charles A.
Hinton Producing Company
Hodge, T. F.
A. J. Hodges Industries Inc.

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Hodges, R. M.
Hoffman, L. C.
Mrs. Luna T. Holcomb
Hollandsworth, G. J.
Hollandsworth and Travis
Holleman, Wilbur J.
Hollyfield and McFarlene
Home-Stake Production Company
Hood, F. M.
Hooper, S. J.
Houston Royalty Company
J. M. Huber Corporation
Huffines, V. R.
Dudley, J. Hughes
Hughey, W. R.
Hughey, W. R. Operating Company
Humble Oil and Refining Company
Hunt, H. L.
Haroldsen L. Hunt, Jr., Trust Estate
Hassie Hunt Trust
Hunt Industries
Lamar Hunt

Lamar Hunt Trust Estate
Hunt, Nelson Bunker Trust Estate
Hunt Oil Company
Hunt Petroleum Corporation
William Herbert Hunt Trust Estate
The Hunter Company, Inc.
Hunter, James A.
Hurley Oil and Gas Company
Hutton, H. L.
Ben C. Hyde, Jr.
Hynson, R. C.

Imperial Production Corporation
Inabnet, W. B.
Inger, Henry S.
Ingersoll Power & Fabricating Company Inc.
International Helium Inc.
Investors Royalty Company, Inc.

Jabco Inc.
Jackson, F. R.
Jackson, J. E.
Jackson, J. E. Inc.
L. B. Jackson Company
T. L. James and Company, Inc.
Javelin Oil Company, Inc.
The Jaybird Corporation
Jenkins, Charles L.
Jenkins-Ray Supply
Jennings, R. L. and Clogg, M. d/b/a Jennings, and Clogg
Jernigan, J. E. & Morgan, M. V. d/b/a Jernigan & Morgan Oil Company
Jernigan and Morgan Transmission Company
Johnson, E. Lyle
Johnson, Gilbert S.
Johnson, Howard C.
Johnson, Rubein V.
Jones, Carroll G.
Jones, James Marshall
Jones, Joseph M.
L. E. Jones Drilling Company
Jones, O'Brien Inc.
Jones, Shelburne and Pellow Oil
Jorden, Jack C., Jr.
Josaline Production Company
Jowoco, Inc.

Karll, R. P.
K. B. Compression Company, Inc.
Keener Oil Company
Kemp, James E.
Kenyon, Clarence
Kerr-McGee Corporation
Ketchum, Ralph F. d/b/a Ketchum Oil Company
Key, Edmund M.
Killingsworth, S. H.

King, Liberto Investments
King, Robert E.
Kinnebrew, Lee
Kinsey, Norman V.
Kirby Petroleum Company
Kirkpatrick Oil and Gas Company
Kubler, E. C., Jr.
R. Lacy, Inc.
Ladner, Heber
Laffoon Oil Company
La Gloria Oil & Gas Company
P. G. Lake, Inc.
William H. Lambdin
The Lancer Corporation
Lando Oil Company
Langford Drilling Company
Lankford, K. D., Jr.
Larco Drilling Company

Lario Oil and Gas Company
Larson, Perry E. and Max L. Thomas
Larue, Fred d/b/a Larue-Smith Prod. Co.
Latham, Joe
Latimer, D. C.
Lechner and Hubbard
LeCuno Oil Corp.
Lee Drilling Company
Lee, R. A. and Ladner, H. L.
Lee, Robert A.
Le Gendre, P. G.
Lemon, I. M., Mrs.
Lerner, W Zolley d/b/a Ko-Ler Oil Company
Lewis, Ethel May Neel
Lillystrand, T. O., Jr.
The Lincoln Converse Company
Little, Quintin
Livingston Oil Company
Lomac Drilling Company
London, D. E.
London Gas Company
Lone Star Producing Company
Longhorn Production Company
Lubell Oil Company
Lynn Drilling Company
Lyons, C. H., Jr.
Lyons and Logan
Lyons, C. H., Sr.

McAlester Fuel Company
W. C. McBride, Inc.
McCain, M. F.
McCalman Drilling Company, Inc.
McCamic, Charles
McCasland, T. H.
McCausland, Oscar B.
McCommons Oil Company
McCommons, Williams E. d/b/a McCommons Exploration Company
McConnell, D. B.
McCord, Charles T., Jr. d/b/a McCord Oil Company
McCulloch Oil Corporation of California
McGoldrick and Watson Drilling Company
McGuire, T. W.
McKnight, Peyton, Jr.
McLemore, B. Regan
McMahon, C. L., Jr.
McMillin, Frank E.
McMurrey, Jim, Estate
McNeish, George R.
McRae, Ethel C.
McWood Corporation
M & M Producing Company
Machin Oil Ltd.
Mack Oil Company
Mackey, Earl T.
Madole, J. D.
Magna Oil Corporation
MaGuire, Russell
Malernee Oil Company
Manziel, Bobby

Manziel, Dorothy N.
Mapco Production Company
Marathon Oil Company
Marcus, Earl
Marks, E. W., Sr.
Marr, M. H.
Marshall Exploration Company Inc.
C. F. Martin Inc.
W. T. Massey and Harry A. Moore d/b/a Massey & Moore
Mathews, Howard
Mayfield Corporation
Maynard Oil Company
Mayronne, R. W., Jr. d/b/a Riverside Oil Company

Maytex Company
Medallion Oil Company
Menefee, J. M.
Mercury Drilling Company
Merrick, Ward S., Jr.
Mid-America Minerals Inc.
Mid Century Oil and Gas Company
Midhurst Oil Corporation
Midway Oil Company
Midwest Oil Corporation
Miles Kimball Company
Miller, Paul L.
Miss-Tex Oil Producers
Mitchell, George and Associates, Inc.
Mitchell, W. H.
Mobil Oil Corporation
Mobley and Stephens
Moffatt, Robert J.
Moffitt, Mrs. Tom J.
Moise, Mrs. Leah H.
W. A. Moncrief
Monla Gas Company Inc.
Monroe Gas System Inc.
Monsanto Company
Morgan Brothers
Morgan, Dave
Morgan, Fred
Morgan, J. A.
Morgan, Margaret M., Mrs.
Morris, C. L.
Morris, P. D.
Mortimer, Mrs. Betty D.
Mosbacher, Robert
Moss, H. S.
Murphy, Charles H., Jr.
Murphy Oil Company of Oklahoma Inc.
Murphy Oil Corporation
Muslow, James
Mutual Investment Company
Myers, Sidney G., Jr.

Nafco Oil and Gas Company Inc.
National Bank of Commerce of Houston
National Fuels Corporation
National Oil Company Inc.
Natol Petroleum Corporation
Natural Gas and Oil Corporation
Neal, T. J.
Nemours Corporation
Neustadt, Doris W.
Newton Naval Stores Company, Inc.
Nichols, Irl A.
Nolan, William C. and T. M.
North Central Oil Corporation
North Louisiana Gas Company Inc.
Norton, Annie
Norton Oil Company Inc.
Norville Oil Company Inc.
Nowery, James R.

O'Boyle, John W.
O'Boyle, Kathleen, Trust No. 2
O'Rourke, D. F.

OK and B Drilling Company
Oklahoma Natural Gas Company
Oliver, Rees R.
Oliphant, A. G.
Olympic Oil Company
Omega Petroleum Corporation
Onstott, L. J. d/b/a Progress Petroleum Products
Orr, B. B.
Osborn, Jewel
Osborn, W. B., Jr.
W. B. Osborn, Jr., Executor The Estate of W. B. Osborn, Sr.
Owen, K. D.

Oxley, John C.
Ozark Gas Corporation

P. S. and G., Inc.
Page, Wiley
Palmer, Milo T.
Pan American Petroleum Corporation
Panola Trading Company, Inc.
Parker, G. C.
Patterson, H. I. and Williams, R. E.
Peake Petroleum Company
Penn, G. E.
Perkins, Elizabeth
Perkins, J. R.
Perkins, J. R. d/b/a Perkins Production Company
Perritt, H. W.
Petroleum Exploration, Inc. of Texas
Petroleum Corporation of Texas
Petroleum Management, Inc.
Pewitt, Paul H.
Phillips, B. F., Estate of
Phillips, Jack L.
Phillips, Leonard W.
Phillips, Loyce
Phillips, O. A., Estate of
Phillips Petroleum Company
Pickens, W. L.
Pioneer Oil and Gas Company, Inc.
Pioneer Oil Investment Company
Placid Oil Company
Porter, L. B.
Potter, Tom
Powers, M. F. Estate
Prentice, Paul R.
Prentiss, W. P.
Price, Jack E.
Proctor, Douglas E., Jr.
Pruet, Chesley

Quiesenberry, W. Y.

R. A. F. Natural Gas Corporation
Radford, C. H.
Raigorodsky, Paul M.
Ray, Lucie L.
Raymond Oil Company, Inc.
Read, Paul L.
Howard M. Redwine
Reed, M. T.
Republic Royalty Company
Reserve Oil and Gas Company
Reynolds Mining Corporation
Rhoades Oil Company
Richardson Oils, Inc.
Richenthal, Arthur
C. R. Ridgway and W. B. Ridgway
Ridgway Management, Inc.
Rimrock Tidelands Inc.
Rio Rojo Gathering System Inc.
Robbins, J. C., Jr.
Robbins Petroleum Corporation

Roberts, J. I.
Roberts, J. I. and Murphy, C. H., Jr. d/b/a Roberts and Murphy
Robinson, L. L.
Robinson & Marshall Drilling Company
Rogers, Hellena Fox Wright
Roosth and Genecov Production Company
Roper, Frank C.
Rorem, S. D.
Rosario Production Company
Henry R. Rose
Ross Production Company

Ross, R. M.
Wilhelmina duP. Ross
Rougon, Dr. and Mrs. A. L.
Rowan, J. Mike
R. D. Roy and Company, Inc.
Roseman, A. M.
Rudco Oil and Gas Company
Rudman, Rose
Ruffin, J. F., Jr. Trustee
Rushing, J. S.
Russ, John
Ryan, Fred H.
Ryan, P. H.
Ryan, Ray

Sabianna Oil Company, Inc.
Samedan Oil Corporation
Martin A. Samuelson
Sanders, Nell E.
Sanford, John T.
Schafer Drilling Company
Schober, Henry I.
Schwartz, C. B.
Scott, Francis W.
Joseph E. Seagram and Sons Inc. d/b/a Texas Pacific Oil Company
Sells Petroleum Inc.
Sellwood and Myers
Service Gas Products Company
Sesco Production Company
Shadid, Fred V.
Shalett, H. T. and Crow, David
Shear, Warren
Shell Oil Company
Shields, Jay M.
Sho Van Gas Producing Company
R. H.. Siegfried Inc.
Siesta Oil and Exploration Company, Inc.
Signal Oil & Gas Company
Simmons, D. J. d/b/a Farrell and Company of Louisiana
Simmons, Jay
Simmons, Maxwell D.
Sinclair Oil & Gas Company
Singer, Joseph B.
Skeeters, A. Z.
Skelly Oil Company
Skelton, D. W.
Sklar, Sam
Slack, Bob B.
Smith, Douglas V.
Smith, E. D.
Smith, H. S.
Smith, J. J.
Smith, L. E.
Smith Operating & Management Company
Smith, P. E.
Smith, R. E.
Smith, Walter R.
Snee, William E.
Sohio Petroleum Company
Sohoma Natural Gas Company, Inc.
South Central Natural Gas Corporation
Southern Union Production Company
Southwest Gas Producing Company
Southwestern Exploration Consultants, Inc.
Stack, J. E., Jr.
R. A. Stacy, Jr.
Standard Oil Company of Texas, a Division of Chevron Oil Company
States Oil Company, Inc.
Stephens Production Company
Stephenson, J. F.
Stewart, Austin E.
D. W. Stewart, Jr., and E. L. Stewart

Strahan, Joe G.
Strength, (Mrs.) Janie R.
Harry J. Strief, Estate of
Stringer, Murray D.
Sun Oil Company
Sunnyland Contracting Company, Inc.
Sunray DX Oil Company
Sunset International Petroleum Corporation
The Superior Oil Company
Sutton, Carol Daube

Tacony Company, The
Talbot, C. P.
Tanner, J. W.
Tate, Ernest W.
Taubert, J. E.
Taylor, Mrs. Douglas Havard
Taylor, McCleland
Teekel, Lloyd G.
Tenneco Corporation
Tenneco Oil Company
Texaco Inc.
Texas Gas Exploration Corporation
Texas San Juan Oil Corporation
Thomas, Evan A.
Thomason, D.
D. Thomason Production Company, Inc.
Thompson, J. Cleo
Tidewater Oil Company
Tittle, W. M.
Todd, Dr. John D.
Toto Gas Company
Trahan, J. C.
J. C. Trahan Drilling Contractor Inc.
Trans-State Oil Company, Division of Hess Oil and Chemical Corp.
Trant, Mike d/b/a Mike Trant Drilling Company
Trant, Sam
Treat, Frank B.
Tri J. Inc.
Trice Production Company
Tuttle, R. M. d/b/a R. M. Tuttle Pipe Line
Twin Gas Company

Union Oil Company of California
Union Producing Company
Union Texas Petroleum, a Division of Allied Chemical Corporation

Vanson Production Corporation
Vaughn, G. H., Jr. and Jack C.
Vaughn, G. H., Jr.
Vaughn Petroleum Inc., Agent
Vaughey and Vaughey
Venters, Harley E.
The Vickers Petroleum Co., Inc.

Wager, Dan R.
Walker, Keith F.
Walker, Ross
Walsh, Frank H.
Wandel, Philip
Wannop, Mary Fitts
Warren American Oil Company
Warren Petroleum Corporation
Wegmann, W. A.
Westates Petroleum Company
Westheimer Neustadt Corporation
Westland Oil Development Corporation
Whelan, D. E. and R. J.

Wheless Drilling Company
Wheless, Joseph Sidney, Jr.
N. H. Wheless Oil Company
Wheless, W. M.
Whitaker, Douglas
Whitaker, John C.
White, Blanche N.
White, Janet
White, T. J., Jr.
Whitehall Oil Company, Inc.
Whittington Number Four
Wichita River Oil Corporation
Wico Oil Company
Wiederhold, William C., Agent
Williams, Charles K.
Williams, E. B., Jr.
Williams, E. B., Sr.
Williams, George H. and Hill
Williams Pressure Service Company
Williams, Robert Gordon
Wilson, Bruce L.
Wilson, Norton F.
Winwell Inc.
Wise Operating, Inc., of Tyler
Wood Oil Company
Woods, Harold L.
Woods Petroleum Corporation
Woolf, Geraldine H.
Worldwide Petroleum Corporation
Worth Drilling Company
Wrather, J. D., Jr.
Hattie C. Wright, Administratix to J. F. Wright
Wunderlich Development Company
W. R. Yinger

Yoakam, Coler, Jr.
Young, Marshall R.
Marshall R. Young Oil Company

Zephyr Drilling Corporation
Zephyr Oil Company

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APPENDIX C

PIPELINE PURCHASERS MADE RESPONDENTS TO THE AREA RATE PROCEEDING (OTHER SOUTHWEST AREA), DOCKET NOS, AR67-1, *ET AL.*

Arkansas Louisiana Gas Company
Cimarron Transmission Company
Cities Service Gas Company
Cushing Gas Transmission Company
El Paso Natural Gas Company
Fort Smith Gas Corporation (now Arkansas Oklahoma Gas Corporation)
Humble Gas Transmission Company
Lone Star Gas Company
Louisiana Nevada Transit Company
Michigan Wisconsin Pipe Line Company
Mississippi River Transmission Corporation
Natural Gas Pipeline Company of America
Panhandle Eastern Pipe Line Company
Rio Sabien, Incorporated
Southern Natural Gas Company
Tennessee Gas Pipeline Company, A Division of Tenneco Inc.
Tensas Gas Gathering Corporation
Texas Eastern Transmission Corporation
Texas Gas Transmission Corporation
Trunkline Gas Company
Union Gas System, Incorporated
United Fuel Gas Company
United Gas Pipe Line Company
Valley Gas Transmission, Incorporated

APPENDIX D

SECTION 4 RATE SUSPENSION PROCEEDINGS[1] CONSOLIDATED FOR HEARING WITH AREA RATE PROCEEDING (OTHER SOUTHWEST AREA), DOCKET NO. AR67-1

Name[2] and Docket Nos.

Amerada Petroleum Corp.; RI65-334
American Petrofina Company of Texas (Oper.), et al.; RI64-442
Appache Corporation; RI63-332
Arkla Exploration Co.; RI64-233, RI64-240, RI64-277, RI66-339
Ashland Oil & Refining Co., et al.; RI60-288

Bander, Joe, et al.; RI67-54
Biglane, D. A., et al.; G-20190
Bond, Durbin; G-20184
Borden, S. P.; G-20191
Bracken Oil Co. (Oper.), et al.; G-16084
Bridewell, Billy (Oper.), et al.; RI63-241

Cameron, A. A., d/b/a Cameron Oil Co., et al.; RI65-521, RI67-80
Carter-Jones Drilling Co., Inc. (Oper.), et al.; RI61-546
Champlin Petroleum Co.; RI63-304
Claiborne Gasoline Co.; RI64-260

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[1] These proceedings are consolidated only insofar as they pertain to sales in the areas enumerated in Appendix A.

[2] This producer designation is for general identification and may not include all of the respondents designated in the respective orders initiating rate suspension proceedings.

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Order Instituting Area Rate Proceeding

Cohen, Don (Oper.), et al.; RI64-421
Coles, Marvin J., et al.; RI64-134
Continental Oil Co.; G-19734, G-19919, G-20197, RI60-193, RI60-223, RI61-249, RI63-217, RI63-350, RI63-368, RI64-165, RI64-166, RI64-784, RI65-231, RI67-72
Continental Oil Co. (Oper.), et al.; RI63-240, RI65-128
Cook, Tom, Jr. (Oper.), et al.; G-16638, RI60-133
Cox, Edwin L.; RI63-219, RI63-428, RI64-68, RI64-573
Cyprus Mines Corp. & Skelly Oil Company (Operator); RI64-8
Coastal States Producing Company; RI67-159

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Davis, C. D., et al., and Car-Tex Producing Co., et al.; RI65-374
Draughn, Paul V., Sr.; RI65-422
Draughn, Paul V., Jr.; RI65-424

Ells, H. A., et al., d/b/a All Star Gas Company; RI63-178

Falcon Seaboard Drilling Co., et al.; RI63-221
Fields, Bert, Estate, et al.; RI64-290
Forest Oil Corp.; RI63-230
Forest Oil Corp. (Oper.), et al.; RI65-125
Four States Drilling Co., Inc. (Oper.), et al.; G-20081

Gant, Walter H. (Oper.), et al.; RI64-254
General American Oil Co. of Texas; RI63-377, RI65-345
Greenville Gasoline Co., Inc. (Oper.); RI63-275
Gulf Oil Corp.; G-11335, G-13519, G-13581, G-16657, G-19742, G-20560, RI60-214, RI61-169, RI61-212, RI62-114, RI63-148, RI64-198, RI64-231, RI64-247, RI65-600
Gulf Oil Corp. & Ashland Oil & Refining Co.; RI65-599

Hall, Stanton A.; RI65-421
Hamman, Blake (Oper.), et al.; RI64-710
Harper Oil Co. (Oper.), et al.; RI63-450, RI65-274
Hefner Co., The (Oper.), et al.; RI63-472
Helmerich & Payne Inc. (Oper.), et al.; RI63-445
Home-Stake Production Co. (Oper.), et al.; RI64-124
Humble Oil and Ref. Co. (Oper.), et al.; RI66-24, RI66-149, RI66-279, RI67-108
Hunt, H. L.; G-13531, G-16642, G-19754
Hunt, H. L., et al.; RI61-203, RI62-136, RI64-44, RI66-131

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Haroldson L. Hunt, Jr., Tr. Est.; RI66-239, RI67-180
Hassie Hunt Trust; G-19752, RI61-206, RI63-104, RI64-213, RI65-265, RI67-100
Hassie Hunt Trust (Oper.), et al.; RI66-130
Hunt, Lamar; G-14936, G-16615, RI61-195, RI62-137, RI63-151, RI64-212, RI65-263, RI66-134, RI67-101
Lamar Hunt Trust Estate; G-14938, G-16618, RI61-194, RI62-105, RI63-150, RI64-215, RI65-264, RI66-135, RI67-102
Lamar Hunt Trust Estate, et al.; RI66-240, RI67-181
Hunt, Nelson Bunker Trust Est.; G-14939, G-16616, RI 61-196, RI62-139, RI63-149, RI64-211, RI65-262, RI 66-136, RI66-241, RI67-103, RI67-182
Hunt Oil Co.; RI63-229, RI66-127, RI66-243, RI67-98, RI67-178, RI67-179
Hunt Oil Co. (Oper.), et al.; RI66-237, RI66-270
Hunt Oil Co., et al.; RI66-242
Hunt Petroleum Corp.; RI65-261
Hunt, William Herbert Trust Est.; G-14937, G-16617, RI 61-197, RI62-140, RI64-216, RI65-253, RI66-125, RI 66-238, RI67-104, RI67-183

Hunter Co. Inc., The; G-19920
Hurley Oil & Gas, et al.; G-16645
Hurley Oil & Gas (Oper.), et al.; & Mobil Oil Corporation; RI62-318, RI64-201
Hyde, Ben C. W., Jr. (Oper.); RI63-279

T. L. James & Co., Inc., et al.; RI66-172, RI66-173
Jernigan, J. E. & Morgan, M. V., d/b/a Jernigan & Morgan Oil Co.; RI63-233
Jernigan & Morgan Transmission Co., RI63-234

R. Lacy, Inc., et al.; G-14315
Laffoon Oil Co.; RI64-689
Landa Oil Co.; G-19028, RI64-730, RI64-740, RI65-397
Lario Oil & Gas Co.; RI64-601
D. C. Latimer; RI61-410
LeCuno Oil Corp.; RI60-459
LeCuno Oil Corp., & Landa Oil Co.; RI61-210
London Gas Co., et al.; RI61-112, RI63-176, RI63-177

McCommons Oil Co., et al.; RI64-21, RI65-568
McCommons, W. E., d/b/a McCommons Exploration Co., et al.; RI63-281
Mack Oil Co.; RI64-18
Mapco Production Co. (Oper.), et al.; RI66-20
Marathon Oil Co., RI66-140, RI67-121, RI66-33, RI66-74
Marathon Oil Co. (Oper.), et al.; RI66-19
Marks, E. W., Sr., et al.; RI62-272
Marr, M. H.; RI66-144
C. F. Martin, Inc.; RI65-372
Maynard Oil Co.; RI64-288, RI67-17, RI67-18
Maynard Oil Co. (Oper.), et al.; RI64-287, RI66-10
Midway Oil Co., et al.; RI64-87

Midwest Oil Corp., RI64-195
Midwest Oil Corp. (Oper.), et al.; RI64-214
George Mitchell & Associates, Inc., Agent for Ann W. Alexander, Executrix, et al.; RI61-239
Mobil Oil Corp.; RI61-113, RI61-188, RI65-196
Mobil Oil Corp. (Oper.), et al.; RI61-114, RI64-210, RI 65-276, RI66-98
Mortimer, Mrs. Betty D., et al.; G-20194
Murphy Oil Corp., et al.; RI61-145
Murphy Oil Corporation; RI61-146

Newton Naval Stores Co., Inc.; RI65-346
North Central Oil Corp., et al.; G-19026
Norville Oil Co., Inc.; RI64-19

Page, Wiley (Oper.), et al.; RI64-203
Pan American Petroleum Corp.; G-13516, G-16629, G-17058, G-19641, G-19765, RI61-167, RI61-192, RI62-151, RI63-81, RI63-138, RI63-231, RI64-222, RI64-231, RI65-178, RI65-277, RI65-294, RI66-129
Pan Amer. Petr. Corp. (Oper.), et al.; RI65-112
Perkins, Elizabeth, et al.; RI64-114
Phillips Petroleum Co.; G-12283, G-16112, G-16113, RI60-257, RI63-394, RI64-619, RI65-127, RI65-577, RI66-324
Phillips Petroleum Co. (Oper.), et al.; RI61-284, RI67-173
Pioneer Oil & Gas Co., Inc., et al.; G-20195, RI61-51

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Placid Oil Co. (Oper.), et al.; G-15370, G-15371, G-17423, G-19767, RI61-176, RI61-193, RI61-213, RI62-104, RI62-144, RI63-132, RI64-202, RI64-239, RI65-259, RI66-132, RI67-91

Ridgway, C. R. & W. B.; G-19932
Ridgway Management Inc.; G-20068
Rimrock Tidelands Inc., et al.; G-15073
Robbins, J. C., Jr.; RI63-475
Robbins Petroleum Corp. (Oper.), et al. and Pan American Petr. Corp.; RI63-476
Roper, Frank C.; RI60-389
Ross, R. M.; RI65-318
Rowan, J. Mike (Oper.), et al.; RI63-293
Ruffin, J. F., Jr., Trustee; G-20192

Samedan Oil Corp.; RI63-466, RI63-467
Joseph E. Seagram Sons Inc., d/b/a Tex. Pacific Oil Co.; RI63-183, RI63-443
Shell Oil Co.; RI64-791, RI65-474, RI65-477, RI65-483
Shell Oil Co. (Oper.); RI65-485
Shell Oil Co. (Oper.), et al.; RI66-14, RI65-476
Shell Oil Co., Cabot Corporation (SW) (Oper.), et al., Herman George Kaiser, & Phillips Petroleum Company (Oper.), et al.; RI65-475
R. H. Siegfried Inc., et al.; RI62-380, RI64-677
Simmons, Maxwell D. (Oper.), et al.; RI63-477
Sinclair Oil & Gas Co.; RI61-530, RI62-152, RI63-131, RI64-257, RI65-14, RI65-38, RI66-77, RI66-86, RI66-345
Sinclair Oil & Gas Co., et al.; RI60-231, RI61-172
Sinclair Oil & Gas Co. (Oper.), et al.; RI64-256, RI65-28, RI66-166
Skelly Oil Co.; RI60-253, RI67-10
Sohio Petroleum Co.; RI66-276, RI67-81
Southern Union Production Co.; RI65-587
Southwest Gas Producing Co., Inc.; RI66-351
Southwestern Explor. Consultants Inc. (Oper.), et al.; RI60-245, RI60-360

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Order Instituting Area Rate Proceeding

Standard Oil Co. of Tex. Div. of Chevron Oil Co., RI63-462
Sun Oil Company, RI66-401

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Sunray DX Oil Co.; RI64-335
Sunset International Petroleum Corp.; RI61-545
The Superior Oil Co.; G-20347, RI61-83
The Superior Oil Co. (Nevada) and James W. Harris; G-14106
The Superior Oil Co. and Gas Rock Corporation; G-18694

Ernest W. Tate; RI66-357
Tenneco Oil Co.; RI63-474, RI65-145
Tenneco Oil Co. (Oper.), et al.; RI64-741, RI65-534, RI 66-87, RI66-369
Tenneco Oil Co., Continental Oil Co.; RI62-539
Texaco Inc.; RI66-329, RI66-383, RI67-2
Tidewater Oil Co. (Oper.), et al.; RI64-726, RI65-129, RI67-78
Tidewater Oil Company & James W. Harris (Oper.), et al.; RI64-762
Todd, Dr. John D.; RI60-352
J. C. Trahan Drilling Contr., Inc. & Marshall R. Young Oil Co.; RI61-499, RI64-722
J. C. Trahan Drilling Contr. Inc. (Oper.), et al.; RI63-21, RI64-329, RI64-380, RI65-548
Twin Gas Co.; RI63-464
Twin Gas Co. (Oper.); RI63-465
Union Oil Co. of Calif. (Oper.), et al.; RI66-316, RI66-317, RI66-426

Union Texas Petroleum Div. of Allied Chemical Corp. (Oper.), et al.; RI64-742, RI65-126

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Order Instituting Area Rate Proceeding

Union Texas Petroleum Div. of Allied Chemical Corp., et al.; RI63-461

Vaughn, G. H., Jr., et al.; RI61-182
Venters, Harley E.; RI66-356

Walker, Ross; RI65-499
Whelan, D. E. and R. J.; RI62-39
Wichita River Oil Corp.; RI64-151
Wunderlich Development Co. (Oper.), et al.; RI65-124

Order Instituting Area Rate Proceeding

[10,934]

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

(Issued February 28, 1967)

ROSS, Commissioner *dissenting in part*:

In refusing to dispense with the Examiners' decisions in the *Hugoton-Anadarko* and *Texas Gulf Coast* proceedings, the Commission now finds itself in the position where it must proceed on an *ad hoc*, case-by-case basis, as I feared. The repetitive, time consuming and expensive procedures of the last seven years are to be repeated. With all the interested parties anxiously awaiting not only a final determination of the *Permian Basin* case, which should come sometime within a year, but also anticipating the Commission's decision itself in South Louisiana, it seems senseless to me to institute still another area rate proceeding.

I agree to securing information which is clearly needed, but I do not agree that we will gain anything in the interim by diverting the attention of all concerned from a determination of the method of establishing just and reasonable rates now underway in pending area cases.

/s/ Charles R. Ross
CHARLES R. ROSS

[11,131]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: Lee C. White, Chairman; L. J. O'Connor, Jr., Charles R. Ross, Carl E. Bagge, and John A. Carver, Jr.

Docket Nos. AR67-1, *et al.*
AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

ORDER ON MOTIONS FOR RECONSIDERATION AND CLARIFICATION

(Issued April 26, 1967)

By motions filed by Continental Oil Company (Continental) on March 27, 1967, Pan American Petroleum Corporation and Sunray DX Oil Company (Pan American, *et al.*) on March 29, 1967, Texaco Inc. and Mobil Oil Corporation (Texaco, *et al.*) on March 30, 1967, Atlantic Richfield Company, Dorchester Gas Producing Company and Magna Oil Corporation (Atlantic, *et al.*) on March 30, 1967, and Humble Oil & Refining Company (Humble) on March 31, 1967, respondents in the above entitled proceeding, reconsideration and clarification are requested of the Commission's Order Instituting Area

[1] The motions filed by Pan American, *et al.*, Texaco, *et al.*, Atlantic, *et al.*, and Humble are styled as being applications for rehearing under Section 19(a) of the Natural Gas Act. However, applications for rehearing are not properly directed to an interlocutory order such as is here under consideration and accordingly the motions are being treated as motions for reconsideration.

Rate Proceeding issued on February 28, 1967.[1] In the main the motions are concerned with the provision in the order which directs the presiding examiner to incorporate by reference all the evidence adduced in the joint record in the Hugoton-Anadarko—Texas Gulf Coast proceedings. The order provided that "specific portions of the joint record may be excluded upon a clear showing of irrelevance or immateriality." It further provided that evidence may be presented on any new issues not raised in the joint record and supplemental data or opinions which are not cumulative or repetitive would also be permitted. While non-repetitive testimony or cross-examination would be allowed on new issues or on matters incorporated by reference, the proceeding essentially would be limited to new evidence respecting area conditions, area costs and rate design.

Continental urges that the "only criteria for restriction of evidence should be relevancy and materiality and duplication" and that the Commission should "make clear that all relevant and nonduplicative evidence will be admissible." As indicated, the order provides that the exclusions from the record will be based upon a clear showing of irrelevance or immateriality. Furthermore, evidence supplementing that already received and evi-

dence which is directed to new issues or relates to area conditions, area costs and rate design would be admissible so long as it met the criteria of relevance, competence, and materiality.

Pan American, *et al.*, contends in its motion that the order could be interpreted as an incorporation by reference of findings of fact as distinguished from incorp-

oration by reference of evidence. Texaco, *et al.*, Atlantic, *et al.*, and Humble likewise claim that the order could be interpreted as meaning that findings or decisions would be incorporated by reference. The order clearly refers only to the evidence adduced and does not refer to findings of fact or decisions by the presiding examiners in other proceedings. Consequently, the record as developed in the instant proceeding will consist of applicable portions of the joint record in the Hugoton-Anadarko—Texas Gulf Coast (not excluded by the examiner), portions of the records in other proceedings incorporated by reference therein, supplemental and updated evidence permitted by the examiner, and evidence on new issues and on area conditions, area costs, and rate design relating to the Other Southwest Area. Thus, whether or not parties to the instant proceeding were parties in the other proceedings, they will have the opportunity to urge the examiner to make findings of fact and law based upon the record in this proceeding as developed either by incorporation by reference as supplemented or updated and such new relevant evidence as may be introduced. The examiner will be free in his decision to make such findings and reach such conclusions as he deems appropriate based upon the entire record in this proceeding. He will not be bound by rulings, findings, or decisions made by the examiners in other proceedings, nor are such findings incorporated in this record. If, in the opinion of any of the parties, evidence was admitted in the aforesaid joint record which should have been excluded for reasons of irrelevance or immateriality and objections on these grounds were made and overruled by the presiding examiners in the other proceedings, the parties are free to urge before the examiner in the instant proceeding that such material

be excluded from the incorporation by reference. In making his rulings herein, the examiner would not be bound by the prior rulings of other examiners.[2]

Pan American, *et al.*, urges that the Commission order should provide that the presiding examiner may divide the hearing into "revenue requirements and rate design phases." The conduct of the hearings and any phasing thereof is strictly within the province of the presiding examiner. If, in his determination, the hearing will be handled most expeditiously by the phasing of the hearings, he is in the best position to so order.

[11,133]

The Commission orders:

The motions filed by Continental, Pan American, *et al.*, Texaco *et al.*, Atlantic, *et al.*, and Humble for reconsideration and clarification of the order issues herein on February 28, 1967, are denied except in the respects above set forth. By the Commission. Commissioner Ross not participating.

[SEAL]

JOSEPH H. GUTRIDE,
Secretary

[2] Accordingly, we delete from the February 28 order those portions thereof which may be inconsistent with our position herein. In the first full paragraph of page 2 of that order on line 10 "a retrial or" is deleted, and starting on line 22", absent new evidence, the same issues shall not be tried in this proceeding but that" is also deleted.

[11,287]

Order Clarifying and Enlarging Definition of Area

[11,287]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: Lee C. White, Chairman; L. J. O'Connor, Jr., Charles R. Ross, Carl E. Bagge, and John A. Carver, Jr.

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

ORDER CLARIFYING AND ENLARGING DEFINITION OF AREA

(Issued December 8, 1967)

On November 13, 1967, Shell Oil Company petitioned the Commission to clarify or enlarge the definition of the Other Southwest Area to include lands on the continental shelf off the shore of Mississippi—both offshore lands subject to the jurisdiction of the State of Mississippi and offshore lands within the Federal domain. This request is unopposed. The Commission staff in its answer to the petition did not oppose including the offshore Federal domain and is of the opinion that offshore lands under the jurisdiction of Mississippi are already included within the area.

Lands off the shore of Louisiana were specifically included in the Southern Louisiana Area. Although the original definition of the Texas Gulf Coast Area did not specifically include offshore areas, the Commission by its its order of April 14, 1964, 31 FPC 922, clarified and amended its original order to include the offshore areas.

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Order Clarifying and Enlarging Definition of Area

In both prior Area Rate Proceedings in which offshore continental shelf lands were adjacent to an onshore production area, the Commission included the offshore lands within the area which was the subject of the proceeding.

Accordingly, the petition of Shell Oil Company will be granted by clarifying and modifying the definition of the Other Southwest Area to include underwater lands on the

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continental shelf off the shore of Mississippi within the Other Southwest Area. The inclusion of these offshore lands within the area is not a determination that the same rates should or should not apply as are upon applicable to onshore production in Mississippi, nor even that the same rates should apply everywhere in the offshore area. Whether rates should differ in different portions of the area or under different conditions within the area is a matter to be included in the final determination of the Area Rate Proceeding and nothing in this order is intended to influence that later determination.

The Commission orders:

The definition of the Other Southwest Area is clarified and modified to include the underwater lands on the continental shelf off the shore of Mississippi including both underwater lands subject to the jurisdiction of the State of Mississippi and underwater lands within the Federal domain.

By the Commission.

KENNETH F. PLUMB,
Acting Secretary

[SEAL]

[11,319]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

PRESIDING EXAMINER'S INITIAL DECISION ON OTHER SOUTHWEST AREA RATES

(Issued September 22, 1969)

APPEARANCES

Edwin S. Nail for Amerada Petroleum Corporation.

Charles F. Wheatley, Jr. for American Public Gas Association.

Robert Roberts, Jr., Blanchard, Walker, O'Quin & Roberts, Bernard A. Foster, Jr., Ross, Marsh & Foster for Arkansas Louisiana Gas Company.

J. N. Clayton, Bernard A. Foster, Jr., Ross, Marsh & Foster for Arkla Exploration Company.

Ted Holshouser for Ashland Oil & Refining Company.

John E. Holtzinger, Jr., Frederick Moring and *J. David Mann, Jr., Morgan, Lewis & Bockius* for Associated Gas Distributors Group, consisting of Atlanta Gas Light Comapny; The Berkshire Gas Company; Boston Gas Company; Bristol and Warren Gas Company; Brockton Taunton Gas Company; Buzzards Bay Gas Company; Cambridge Gas Company; Central Massachusetts Gas Company; City of Holyoke, Massachusetts

Gas and Electric Department; City of Norwich, Department of Public Utilities; City of Westfield Gas and Electric Light Department; Concord Natural Gas Corporation; The Connecticut Gas Company; Fall River Gas Company; Fitchburg Gas and Electric Light Company; Gas Service, Inc.; The Greenwich Gas Company; The Hartford Electric Light Company; The Hartford Gas Company; Haverhill Gas Company; Lawrence Gas Company; Lowell Gas Company; Lynn Gas Company; Manchester Gas Company; Mystic Valley Gas Company; New Bedford Gas and Edison Light Company; The New Britain Gas Light Company; The Newport Gas Light Company; Northampton Gas Light Company; North Attleboro Gas Company; North Shore Gas Company; Norwood Gas Company; The Pequot Gas Company; Providence Gas Company; South County Gas Company; The Southern Connecticut Gas Company; Springfield Gas Light Company; Tiverton Gas Company; Valley Gas Company; Wachusett Gas Company; Worcester Gas Light Company; Brooklyn

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Union Gas Company; Central Hudson Gas and Electric Corporation; Consolidated Edison Company of New York, Inc.; The East Ohio Gas Company; Consolidated Gas Supply Corporation; Lake Shore Pipeline Company; The Peoples Natural Gas Company; The River Gas Company; Elizabethtown Gas Company; Long Island Lighting Company; New Jersey Natural Gas Company; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; Philadelphia Electric Company; Philadelphia Gas Works, Division of UGI Corporation; Piedmont Natural Gas Company, Inc.;

Public Service Company of North Carolina; Public Service Electric and Gas Company; Rochester Gas and Electric Corporation; South Jersey Gas Company; UGI Corporation; and Washington Gas Light Company.

Stuart J. Scott, Robert E. Wade, Bernard A. Foster, Jr., Ross, Marsh & Foster for Atlantic Richfield Company.

J. Evans Attwell, Vinson, Elkins, Weems & Searls for Austral Oil Company, Inc., Alfred C. Glassell, Jr., *et al.*, George Mitchell & Associates, Inc., Richardson Oils, Inc., Robert Mosbacher, J. Hughes Dudley and A. C. Glassell.

John W. Glendening, Jr. and *John S. Schmid, Glendening and Schmid* for The Berkshire Gas Company; Boston Gas Company; Bristol and Warren Gas Company; Brockton Taunton Gas Company; Buzzards Bay Gas Company; Cambridge Gas Company; Central Massachusetts Gas Company; City of Holyoke, Massachusetts Gas and Electric Department; City of Norwich, Department of Public Utilities; City of Westfield Gas and Electric Light Department; Concord Natural Gas Corporation; The Connecticut Gas Company; Fall River Gas Company; Fitchburg Gas and Electric Light Company; Gas Service, Inc.; The Greenwich Gas Company; The Hartford Electric Light Company; The Hartford Gas Company; Haverhill Gas Company; Lawrence Gas Company; Lowell Gas Company; Lynn Gas Company; Manchester Gas Company; Mystic Valley Gas Company; New Bedford Gas and Edison Light Company; The New Britain Gas Light Company; The Newport Gas Light Company; Northampton Gas Light Company; North Attleboro Gas Company; North Shore Gas Company; Norwood Gas Company; The Pequot Gas Company; Providence Gas Company; South County Gas Company; The Southern Connecticut Gas Com-

pany; Springfield Gas Light Company; Tiverton Gas Company; Valley Gas Company; Wachusett Gas Company; Worcester Gas Light Company.

Edwin F. Russell, Jr. and *Barbara M. Suchow, Cullen and Dykman* for The Brooklyn Union Gas Company.

Mary Moran Pajalich, J. Calvin Simpson and *Sheldon Rosenthal* for The People of the State of California and The Public Utilities Commission of California.

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Woollen H. Walshe, Justin R. Wolf and *Eugene E. Threadgill, Wolf & Case* for The California Company, a Division of Chevron Oil Company.

Gould & Wilkie for Central Hudson Gas & Electric Corporation.

Mathias M. Mattern for the City of Chicago.

Cecil C. Cammack, Graydon D. Luthey, and *R. J. Leithead* for Cities Service Oil Company, Cities Service Company, and Columbian Fuel Corporation.

Charles S. Rhyne, Rhyne & Rhyne for City Group Gas Defense Association, consisting of the Kansas Cities of Altamont, Atchison, Chanute, Countryside, Erie, Fairway, Girard, Grenola, Howard, Iola, Leavenworth, Neodesha, and Prairie Village; and the Missouri Cities of Aurora, Carl Junction, Carthage, Independence, Joplin, Kansas City, Marshall, Monett, Mt. Vernon, Neosho, Nevada, Oronogo, St. Joseph, Springfield, Waverly, and Webb City.

Halcyon G. Skinner and *Lex K. Larson, LeBoeuf, Lamb, Leiby & Mac Rae* for Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation, and Orange and Rockland Utilities, Inc.

K. M. Waters, Jr., C. William Cooper, H. B. Griffith, Jr., Lawrence L. Gray, Norman A. Flaningam, Henry A. Jackson, Thomas G. Roderick and *Thomas A. White* for Consolidated Gas Supply Corporation.

Bruce R. Merrill, Joseph C. Johnson and *Thomas H. Burton* for Continental Oil Company.

Edward Kliewer, Jr. for Delta Drilling Company, Elizabeth F. Dorfman Trust, Louis Dorfman, Sam Y. Dorfman, Jr. and S. L. Florsheim.

J. G. Eckel, Bernard A. Foster, Jr., Ross, Marsh & Foster for Dorchester Gas Producing Company.

C. William Cooper, H. B. Griffith, Jr., Lawrence L. Gray, Norman A. Flaningam, Henry A. Jackson, Thomas G. Roderick and *Thomas A. White* for The East Ohio Gas Company, The River Gas Company, Lake Shore Pipeline, Co., and The Peoples Natural Gas Company.

G. Scott Cuming, Walter G. Henderson, C. Frank Reifsnyder and *Stanley S. Harris, Hogan & Hartson* for El Paso Natural Gas Company.

John R. Sailer for Elizabethtown Gas Company.

John L. Arrington, Jr., Lupardus, Holliman and Huffman for Falcon Seaboard Drilling Company.

C. R. Eyster and *Richard F. Generelly* for Forest Oil Corporation.

Warren M. Sparks and *Donald R. Arnett* for Gulf Oil Corporation and Warren Petroleum Corporation.

Blake Hamman in propria persona.

Richard F. Generelly, May, Shannon and Morley for H. L. Hawkins & H. L. Hawkins, Jr., Houston Royalty Company and Norton Oil Company, Inc.

Douglas J. Miles for Humble Gas Transmission Company.

Martin N. Erck, Frank S. Troidl, Robert L. Norris, Jr., and *J. Kirby Ellis* for Humble Oil & Refining Company.

Robert W. Henderson, Paul W. Hicks and *Donald K. Young* for Hunt Oil Company, H. L. Hunt, Haroldson L. Hunt, Jr., Trust Estate, Hassie Hunt Trust, Hunt Industries, Lamar Hunt, Lamar Hunt Trust Estate, Nelson Bunker Hunt Trust Estate, Hunt Petroleum Corporation, William Herbert Hunt Trust Estate, and Placid Oil Company.

L. Dan Jones and *William I. Powell* for Independent Petroleum Association of America.

John F. Gaston for Iowa Electric Light and Power Company.

Bertram D. Moll for Long Island Lighting Company.

Robert W. Russell for the City of Los Angeles.

H. E. McCommons in propria persona.

Bernard A. Foster, Jr., Ross, Marsh & Foster for Magna Oil Corporation, and J. C. Trahan, Drilling Contractor, Inc.

Jack Fariss for Marathon Oil Company.

F. W. Reese for M. H. Marr.

Richard M. Merriman and *Peyton G. Bowman, III, Reid and Priest* for Michigan Gas Utilities Company.

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David P. Van Note for Michigan Public Service Commission

Charles V. Shannon, May, Shannon and Morley and *Paul S. Davis* for Michigan Wisconsin Pipe Line Company.

John F. Brown for Mississippi River Transmission Corporation.

Charles B. Swanner, R. D. Haworth, Charles S. Chester and *James L. Armour* for Mobil Oil Corporation.

Richard F. Generelly for Monsanto Company.

E. H. Hasenberg for Natural Gas Pipeline Company of America.

Kent H. Brown and *Morton L. Simons* for The Public Service Commission of the State of New York.

Harry L. Bristol, Naylor, Aronson, Huber & Magill for New York State Electric & Gas Corporation.

Lauman Martin for Niagara Mohawk Power Corporation.

George W. Ryerson for Northern Illinois Gas Company.

Edmund A. Schroer and *Joseph T. Morrow, Lawyer, Schroer & Eichhorn* for Northern Indiana Public Service Company.

Lewis G. Mosburg, Jr., Mosteller, Andrews & Mosburg for Oklahoma Independent Petroleum Association.

John L. Arrington, Jr., Lupardus, Holliman and Huffman for Oklahoma Natural Gas Company.

Frederick T. Searls, Malcolm H. Furbush and *Stanley T. Skinner* for Pacific Gas and Electric Company.

John Ormasa, Eric W. Martens, William H. Owens, R. D. Twomey, Jr., and *K. R. Edsall* for Pacific Lighting Service and Supply Company.

J. P. Hammond and *William H. Emerson* for Pan American Petroleum Corporation.

W. P. Anderson for Panhandle Eastern Pipe Line Company.

Herbert E. Squires for Pennsylvania Public Utility Commission.

Samuel G. Miller, Henry P. Sullivan and *Donald Blanken* for Philadelphia Electric Company.

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William T. Coleman, Jr. and *Robert W. Maris, Dilworth, Paxson, Kalish, Kohn & Levy* for Philadelphia Gas Works, Division of The United Gas Improvement Company.

Kenneth Heady and *John R. Rebman* for Phillips Petroleum Company.

James V. Landress for W. L. Pickens.

Stanley M. Morley, May, Shannon and Morley for Pipeline Purchaser Group, consisting of Southern Natural Gas Company, Texas Eastern Transmission Corporation, United Gas Pipe Line Company, Natural Gas Pipeline Company of America, Tennessee Gas Pipeline Company, Texas Gas Transmission Corporation, Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Cities Service Gas Company, and Lone Star Gas Company.

J. Harry Mulhern, Edward S. Kirby and *James R. Lacey* for Public Service Electric and Gas Company.

Norman P. Hines, Jr. for Reserve Oil and Gas Company.

Lynn R. Coleman for Richardson Oils, Inc.

Richard N. George, Nixon, Hargrave, Devans & Doyle for Rochester Gas and Electric Corporation.

Sherman Chickering, C. Hayden Ames and *Donald J. Richardson, Jr., Chickering & Gregory* for San Diego Gas & Electric Company.

Gene P. Morrell for Samedan Oil Corporation.

James D. McKinney, Jr., Ross, Marsh and Foster for Service Gas Products Company.

Oliver L. Stone, Thomas G. Johnson and *Dan A. Bruce* for Shell Oil Company.

A. E. Stebbings, Michael P. Kelly, Bradford Ross and *James D. McKinney, Jr., Ross, Marsh & Foster* for Signal Oil and Gas Company and Service Gas Products Company.

Rex Short, Charles E. McGee, John T. Ketcham and *Charles E. Holmes* for Sinclair Oil Corporation.

John Ormasa, Eric W. Martens, R. D. Twomey, Jr., and *K. R. Edsall* for Southern California Gas Company and Southern Counties Gas Company of California.

Hugh J. Morgan, Jr. for Southern Natural Gas Company.

Robert C. Koury, Cole, Koury, Cole and Tighe for South Jersey Gas Company.

T. A. McEachern, Jr., for Southwest Gas Producing Company, Inc.

Claude Proctor, Justin R. Wolf and *Eugene E. Threadgill, Wolf & Case* for Standard Oil Company of Texas, a Division of Chevron Oil Company.

Phillip D. Endom, Francis H. Caskin, May, Shannon and Morley for Sun Oil Company.

Homer E. McEwen, Jr. for Sunray DX Oil Company.

H. W. Varner and *William T. Kilbourne* for The Superior Oil Company.

William K. Tell, Jr., William R. Slye and *James D. Annett* for Texaco Inc.

Crawford C. Martin, C. Daniel Jones, Jr. and *Linward Shivers* for The State of Texas and the Railroad Commission of Texas.

John Davenport for Texas Independent Producers & Royalty Owners Association.

Raymond N. Shibley and *William J. LeBuhn, Patterson, Belknap, Farmer, Shibley & Wells* for Trunkline Gas Company.

George C. Bond for Union Oil Company of California.

Thomas Fletcher for Union Producing Company.

Elliot G. Flowers, Justin R. Wolf and *Eugene E. Threadgill, Wolf & Case* for Union Texas Petroleum, a Division of Allied Chemical Corporation.

J. David Mann, Jr. and *John E. Holtzinger, Jr., Morgan, Lewis & Bockius* for The United Gas Improvement Company.

Saunders Gregg for United Gas Pipe Line Company.

Paul E. Reichardt for Washington Gas Light Company.

George J. Eckert for Westates Petroleum Company.

Thomas M. Knebel, Rea, Cross & Knebel for Willmut Gas and Oil Company.

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William E. Torkelson for Public Service Commission of Wisconsin.

Reuben Lozner, Robert W. Perdue, Kenneth F. Plumb, Walter J. Kendall, III, Richard V. Mattingly, Jr., and *Robert A. Jablon* for the staff of the Federal Power Commission.

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PURDUE, PRESIDING EXAMINER: This is a proceeding to fix rates for sales by independent producers, in interstate commerce, of natural gas produced in the "Other Southwest Area." Such term is used to distinguish the proceeding from prior proceedings of like nature involving areas elsewhere in the southwest. The region here embraced, the Other Southwest Area, comprises the whole or part of six States; *viz.*, four counties in northwest Alabama; Mississippi (onshore and offshore); Arkansas; that portion of Louisiana north of the 31° parallel; 56 counties in eastern and southern Oklahoma (hereinafter referred to as "other Oklahoma"); and Railroad Commission Districts Nos. 5, 6, and 9 in northeast Texas.

By order issued February 28, 1967, the Commission instituted the proceeding "to determine just and reasonable rates" for the area, under Section 5(a) of the Natural Gas Act. The order named as respondents, 795 independent producers and 24 pipeline purchasers; and consolidated for hearing with the area rate proceeding, 347 rate suspension proceedings under Section 4(e) of the Act, involving 162 producers. By subsequent action, 78 of the respondent independent producers were deleted; certain of the suspension proceedings were severed or terminated; and in other suspension proceedings, new parties were added as corespondents. The remaining respondent independent producers are listed in Appendix A hereto; the respondent pipeline purchasers, in Appendix B; and the present consolidated suspension proceedings, 300 in number, involving 160 producers (as of August 31, 1969), in Appendix C. The order recites that the respondent independent producers are "all persons making sales of gas in interstate commerce from the

production areas delimited herein"; and that the pipeline purchasers "make purchases in [such] producing areas," and hence are directly "concerned" with the determination to be made herein. The order directed the Examiner to incorporate by reference all the evidence adduced in the joint record in *Hugoton-Anadarko Area Rate Proceeding*, Docket No. AR64-1, and *Texas Gulf Coast Area Rate Proceeding*, Docket No. AR64-2 (these proceedings and record are hereinafter referred to as "the joint proceeding" and "the joint record"). The order contained a proviso that after receipt of the joint record, specific portions might be rejected by ruling of the Examiner on the ground of irrelevancy or immateriality.

On June 28, 29, and 30, and September 12, 1967, a prehearing conference was held in the instant proceeding. The conference in

effect constituted part of the hearing in that the Examiner (as theretofore prescribed by him) received the joint record in evidence and ruled on motions to strike portions thereof.

On October 17 and 18, 1967, a phase of the hearing was held in Dallas, Texas, to enable small producers to make a statement of position or to adduce evidence. A "small producer" is a natural-gas company having jurisdictional sales of not more than 10,000,000 Mcf annually on a nationwide basis. At the Dallas sessions, statements of position were made by respondent small producers M. H. Marr, Estate of Russell Maguire, W. L. Pickens, Richardson Oils, Inc., McCommons Exploration Company, Samedan Oil Corporation, McCommons Oil Company, and Hurley Oil and Gas Company; and by intervenor Texas Independent Producers & Royalty Owners Association (TIPRO), whose 4,500 members are small

unintegrated producers and royalty owners in Texas. Richardson, TIPRO, and small producer Robert Cargill adduced evidence.

All other sessions of the hearing were in Washington, D. C. Prepared testimony and exhibits constituting the parties' and participants' cases-in-chief having been served and filed, on January 10, 1968, the Examiner held a short session of the hearing in order to have the testimony copied in the transcript, subject to later adoption by the witnesses.

The proceeding came on for hearing proper before the Examiner on March 20, 1968, and concluded on September 19, 1968, consuming 55 hearing days. The transcript, including the prehearing conference and the sessions at Dallas, totaled 6,939 pages. One hundred and seventeen exhibits, 16 items incorporated by reference to other Commission proceedings, and 3 public document items, were received in evidence. At the prehearing conference, the Dallas phase of the hearing, and the main hearing, appearances of respondents, intervenors, and the staff of the Federal Power Commission were entered as listed under the caption hereof.

A number of the respondent major independent producers cooperated in expediting the hearing by joining in the presentation of evidence and cross-examination of witnesses, and in making motions and responses to motions. They reserved the right, however, to participate individually. (1:17 *et seq.*) These companies, referred to herein as "the principal producer group" or "the producer group," are the following: Gulf Oil Corporation, Warren Petroleum Corporation, Amerada Petroleum Corporation, Ashland Oil & Refining Company, Atlantic Richfield Company, The California Company a Division of Chevron Oil Company, Cities Service Oil Company, Cities

Service Company, Continental Oil Company, Getty Oil Company, Humble Oil & Refining

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Company, Marathon Oil Company, Midhurst Oil Corporation, Midwest Oil Corporation, Murphy Oil Corporation, Pan American Petroleum Corporation, Shell Oil Company, Signal Oil and Gas Company, Service Gas Products Company, Sinclair Oil Corporation, Sohio Petroleum Company, Southwest Gas Producing Co., Inc., Sun Oil Company, Tenneco Oil Company, Texaco Inc., and Union Producing Company.[1] The following respondents participated to a limited extent in the hearing: major independent producers Phillips Petroleum Company; The Superior Oil Company; Hunt Oil Company together with associated companies and persons (the Hunt group); George Mitchell & Associates, Inc. (GMA), an operator for a large number of small independent producers in Texas Railroad Commission District No. 9; and six small independent producers in such district. Intervenors the Associated Gas Distributors group (AGD), comprised of 64 public utilities engaged in the distribution of natural gas, and the staff of this Commission, participated throughout the hearing. Evidence both oral and documentary was introduced by the respondent producers who participated in the hearing, with minor exceptions; by AGD, and by the staff. Cross-examination of witnesses was conducted by said respondents, intervenors, and the staff. After the conclusion of the hearing, briefs were filed by the following parties and participants: the principal producer group (adopted by Phillips and Mobil Oil Corporation, and by Superior in part), Superior, the

[1] Getty Oil Company did not enter an appearance at the hearing but joined in the briefs filed by the principal producer group.

Hunt group, GMA, Richardson, the respondent pipeline purchaser group, AGD, Texas Independent Producers & Royalty Owners Association, intervenor the State of Texas, and the staff.[2] The proceeding was thus submitted for consideration and decision.

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I. IMPROPER ARGUMENT

At pages 21-22 of their initial brief, the principal producer group quote an excerpt from a printed address; at page 40, they cite a printed address; at page 191, footnote 111, they cite and quote excerpts from a "study" by a bank; at page 196, footnote 114, they make statements based on a "study" prepared for a brokerage concern; at page 198, footnote 116, they cite an article in the *Wall Street Journal*; and at page 250, footnote 138, they refer to the contents of an application in another proceeding.

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[2] Pan American filed a supplemental reply brief. The following counsel who did not enter appearances at the hearing were on the briefs: *Joseph W. Morris* for Amerada Petroleum Corporation; *Edward J. Kremer* for Atlantic Richfield Company; *E. L. Creasey* for Cities Service Oil Company and Cities Service Company; *Clyde E. Willbern* for Getty Oil Company; *Morton Taylor* for Marathon Oil Company; *Neal Powers, Jr., Butler, Binion, Rice, Cook & Knapp* for Midhurst Oil Corporation; *James E. Bye, Holme, Roberts & Owen* for Midwest Oil Corporation; *H. Y. Rowe* for Murphy Oil Corporation; *Richard F. Remmers* for Sohio Petroleum Company; *A. T. Shotwell, Shotwell, Brown & Sperry* for Southwest Gas Producing Co., Inc., *Homer E. McEwen, Jr.*, for Sun Oil Company; *Joseph Tamasy* and *John E. Watson* for Tenneco Oil *Robert E. Newey* for Texaco Inc.; and *J. C. Ohrt* for Union Producing Company—all on brief of principal producer group; *Frank P. Saponaro, Jr.* for Superior; *Vinson, Elkins, Weems & Searls* for Richardson; *E. M. Barrett, Ira L. Freilicher, L. George Folsom, Ronald D. Jones, Myles V. Whalen, Jr.*, and *Dale A. Wright* for AGD; and *Nola White* for the State of Texas.

At pages 4 and 5 of their reply brief, the principal producer group quote from a letter, dated December 16, 1968, to the then Chairman of the Commission from W. Morton Jacobs, president of American Gas Association, Inc., and from a petition of Independent Natural Gas Association of America, dated December 2, 1968, to intervene in another proceeding. They also make an averment at page 4 based on other "recent communications to the Commission." The letter and the petition are set out in full as Appendixes B and C to the brief. At page 7, the producer group make an averment based on the AGA letter to the Chairman. At page 8, footnote 7, they quote another excerpt from the AGA letter. At pages 9 and 10, they make an averment based on the contents of "extensive applications for rehearing filed by various parties" in another proceeding and "motions" therein "of various pipelines and other nonproducers"; and in an accompanying footnote they cite a certain motion in the other proceeding and a "joinder" therein.

At page 20 of their reply brief, footnote 13, the principal producer group cite briefs of the staff and AGD in another proceeding as basis for a statement made. At page 41, they make a statement based on, and quote from, a staff brief in another

proceeding. At page 68, footnote 36, they quote testimony of a witness in *Southern Louisiana Area Rate Proceeding*, Docket No. AR61-1. At page 118, footnote 49, they make a statement based on an application for rehearing in another proceeding. At page 15 of its supplemental reply brief, footnote 14, Pan American makes a statement based on briefs of the staff and AGD in another proceeding.

At page 7 of their initial brief, the pipeline purchaser group cite the same bank study quoted in the producers' initial brief, page 191.

At pages 85, 97, and 106 of their initial brief, the staff cite five articles in *The Oil and Gas Journal*.[3]

None of the material referred to in the five preceding paragraphs is a part of the record. At the hearing, the Examiner repeatedly rejected similar material on the ground of hearsay and immateriality. (See, *e.g.*, 3:377-81; 7:824-35; 58:6164-72; 64:6708-09.) The materials mentioned in the foregoing paragraphs not being evidence in the case, their use is improper argument. The Examiner gives no consideration to them.

At pages 213-14 of their initial brief, an argument of the principal producers is based on material rejected by the Examiner and made an "offer of Proof." The Examiner ignores this improper argument. An offer of proof is not evidence. The purpose of Rule 43(c) of the Federal Rules of Procedure, permitting an offer of proof, is to enable the reviewing court intelligently to pass upon the question as to the admissibility of the excluded matter. *Pennsylvania Lumbermens Mutual Fire Insurance Co.* v. *Nicholas* (C.A. 5), 253 F.2d 504, 507. To argue a case to a trial examiner on the basis of material which he rejected is frivolous.

In the reply brief of the principal producer group, pages 11 and 12, two more offers of proof are cited as

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[3] One of these articles was referred to in the prepared testimony of a producer witness, 57:6060; and was stricken out by the Examiner, 58:6165. Manifestly, the staff inadvertently overlooked this ruling.

In this decision, in citing the transcript in this proceeding and portions of transcripts incorporated by reference, the first figure is the transcript volume; the subsequent figure or figures are the transcript page or pages.

basis for statements made. The Examiner does not give consideration to these statements for the same reason.

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At pages 102 and 103 of their reply brief, the producer group set out a table and make averments based on Schedule 2 of Exhibit D of Exhibit 129-J in *Hugoton-Anadarko* and *Texas Gulf Coast*. Exhibit 129-J is incorporated by reference in this proceeding but was made the subject of a motion to strike. The Examiner ruled that Schedule 2 of Exhibit D thereof "will be allowed to stand only for" a specified "limited purpose." (3:354-56.) The table and language at pages 102 and 103 violate this ruling. Such Schedule 2 was part of the offer of proof referred to at pages 213-14 of the producer group's initial brief. The producer group may be making its argument because of this offer of proof. Whatever the reason, the Examiner gives no consideration to such improper argument.

Likewise, at pages 3 and 4 of its initial brief, Superior makes an argument based in part on Exhibit 21 for Identification, which was rejected, and certain testimony of Don W. Prescott and Pat F. Timmons which was stricken out (Examiner's ruling issued January 16, 1968), which material was made the subject of an offer of proof. The Examiner gives no consideration to the rejected exhibit or the stricken testimony.

Again, at pages 6 to 10, inclusive, of its initial brief, Superior makes an argument based in part on Schedule 2 of Exhibit D of Exhibit 129-J in the joint proceeding, in violation of the Examiner's ruling in Volume 3, pages 354-56 of the transcript; based in part on Exhibits 109-J and 130-J in the joint proceeding, which the Examiner struck out in this proceeding (3:362); and based in part

on testimony of Clark W. Breeding in support of the proposition that the respondent producers pay certain claimed amounts as income taxes, which testimony the Examiner rejected insofar as it went to such question. (3:361-62.) The Examiner gives no consideration to Exhibits 109-J, 130-J, and the calculation at page 8 of Superior's brief from Exhibit D of Exhibit 129-J; and gives no consideration to the remainder of the foregoing material except for the limited purposes specified in his rulings at the hearing.

At page 71 of their initial brief, the principal producer group cite data from U.S. Bureau of the Census, *Long Term Economic Growth: 1860-1965* (1966); at page 75, they cite a table from an issue of *Fortune* (June 1968) and a table from Board of Governors of the Federal Reserve System, *Federal Reserve Bulletin* (September 1968); at page 86, footnote 56, they make statements based on citations to certain pages of the *Congressional Record*; at page 198, footnote 117, they make statements based on *Economic Report of the President*, issues of January 1963 and February 1968; and at pages 206-07, they cite material from *The American Association of Petroleum Geologists Bulletin* (June 1966). At page 83 of their initial brief, the staff quote two excerpts

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from American Gas Association, Inc., *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1967* (May 1968); and at page 84, the staff quote an excerpt from U.S. Atomic Energy Commission, El Paso Natural Gas Co., and the Department of the Interior, *Project Gasbuggy* (September 15, 1967). These data and materials are not a part of the record. Had they been offered in evidence,

the Examiner might have received them, in line with rulings receiving similar matter. Near the outset of the hearing, the Examiner even put the participants on notice that they would be required to prove their case by introducing in evidence the material upon which they rely or by otherwise making a proper evidentiary showing during the hearing. (10:1364-66.) The use of these materials in the briefs is improper argument, which the Examiner ignores in reaching his decision.

It may be contended that the Examiner should now take official notice of the citations above referred to from government and American Gas Association publications, even though they were not received in evidence. This contention is unwarranted for two reasons. First, neither the parties nor the staff have complied with the provisions of *Rules of Practice and Procedure*, Section 1.26(d), that, "Any participant requesting the taking of official notice after the conclusion of the hearing must set forth the reasons claimed to justify failure to make the request prior to the close of the hearing." Second, due process may require that a party be afforded opportunity to challenge such noticed facts and "parry their effect" by evidence and proper argument, if he desires to do so. *Ohio Bell Telephone Co.* v. *Public Utilities Commission*, 301 U.S. 292, 301-02; *United States* v. *Abilene & Southern Railway Co.*, 265 U.S. 274, 289. This proceeding must be brought to conclusion, and the likelihood of having to reopen the hearing should be avoided.[4]

[4] Section 1.27(d) of the Rules of Practice makes a distinction between the participants on the one hand and the Examiner and the Commission on the other respecting official notice of facts. The Examiner and the Commission have broad authorization, on their own account, to take official notice after the conclusion of the hearing. This distinction is proper. The participants have the opportunity during the course of the hearing to make out their case. But the Examiner and the Commission, upon studying the record in

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II. PRELIMINARY FINDINGS OF FACT

The evidence establishes the following facts:

General

Petroleum was first discovered in the Other Southwest Area in 1866. The first recorded natural-gas discovery was in 1901. (9:944-45.) Gas production assumed major importance in the middle 1920's, when natural gas was piped from the area to markets in southeastern Texas and southern Louisiana; and soon thereafter to Memphis and St. Louis. (9:946, 949.) The tremendous expansion of demand following World War II brought many pipelines into the area seeking sources of supply. The 24 respondent pipeline companies now purchase gas there. (9:950; Order, Feb. 28, 1967, App. B.)

Total gas production in the area in 1967 was 2.2 trillion cubic feet, representing about 12% of total continental United States gas production. (Ex. 70, p. 26.)

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preparing their decision or opinion, may discover points on which additional information is needed. It is proper administrative procedure for the Examiner and the Commisison to avail themselves (as they are authorized to do by Section 1.27(d)) of such material "as might be judicially noticed by the courts of the United States," or "as to which the Commission by reason of its functions is an expert." However, if a reopening of the hearing is to be obviated, the Examiner and the Commission should not make use of extra-record materials which a party should reasonably have an opportunity to meet. See Davis, *Administrative Law Treatise*, Vol. 2, p. 344.

In the instant decision, the Examiner has in certain instances taken official notice of material which he is satisfied will not call for a reopening of the hearing—principally updated statistical data not available before the close of the hearing or at the time witnesses prepared their exhibits.

Gas-well gas has accounted for about 50% of total gas production in the area in recent years. (Ex. 8, p. 183.)

In 1966, approximately 38% of the gas produced was sold in interstate commerce; and 62% was consumed in intrastate commerce. (Ex. 4, p. 30.) As of 1964, of the volume sold interstate, approximately 48% was consumed in the eastern part of the United States (New England, Appalachian and Southeast regions); 18%, in the Great Lakes-Northern Plains regions; and the remaining 34%, in the Mid-Continent and Gulf Coast regions. 9:1082; calculation based on Ex. 4, pp. 28-30.)

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The year-end 1967 proved gas reserves in the Other Southwest Area, 26.5 trillion cubic feet, represents about 9% of the proved reserves in the continental United States. (Ex. 70, p. 25.) This volume is less than the proved gas reserves in any of the areas heretofore the subject of this type of proceeding; *viz.*, *Permian Basin Area Rate Proceeding*, 34 F.P.C. 159, 34 F.P.C. 1068, 34 F.P.C. 1286, *Permian Basin Area Rate Cases*, 390 U.S. 747; *Southern Louisiana Area Rate Proceeding*, Opinion No. 546; *Hugoton-Anadarko* and *Texas Gulf Coast*, *supra*. The proved reserves in the Southern Louisiana Area are about three times as great. (Ex. 70, p. 25.)

Annual reserve additions (new supply) in the Other Southwest Area have been nearly in balance with annual production during the period 1956-1967, and the year-end reserves to production ratio has remained fairly constant during that period, ranging from a low of 11.0 to a high of 12.8. (Ex. 70, p. 27.)

In his initial decision in *Hugoton-Anadarko*, Examiner Kane correctly found:

"By order of October 30, 1963, the Commission issued a questionnaire to 114 natural-gas production companies making sales of natural gas for resale, seeking 1962 cost and related operating data. Responses were required of (a) independent producers having annual nationwide jurisdictional sales in excess of 10,000,000 Mcf, (b) pipelines having annual production in excess of 10,000,000 Mcf and (c) all pipeline affiliates [oil and gas production affiliates of pipeline companies—31 F.P.C. 34, 35] whether or not their annual sales or production was in excess of 10,000,000 Mcf.

"Ninety companies filed responses to the questionnaire. Of the 24 producers who did not file, four were excluded for reasons of duplication, and the remainder were relieved from filing because their annual sales or production were less than the adopted standard. For various undisputed reasons, the Staff did not use the data from six of the companies in compositing its cost data. The remaining 84 companies comprise 69 producers and pipeline affiliates and 15 pipeline producers." (Mimeo., 9-10.)

Fifty-eight independent producers (including production affiliates of pipeline companies) and eight pipeline companies having production in the Other Southwest Area filed responses to the questionnaire. By a supplemental order issued February 28, 1967, the Commission directed that certain additional data involving gathering and processing costs be supplied for the

Other Southwest Area. This order was sent only to producer respondents to the AAQ, but the additional data were furnished by AAQ pipelines as well. (See order herein dismissing appeal, issued March 4, 1968.) The cost

studies used by the staff in this proceeding are based on the responses of the 58 independent producers.

This entire group of 66 companies (58 independent producers and 8 pipelines) includes all major producers operating in the area. (Ex. 13, pp. 56-57.) Their gas production accounted for over 50% of the total in the area.

The 1962 lease revenue in the area of these 66 companies was:

	Production	Lease Revenues	
	(Barrels or Mcf)	($)	
Crude Oil	197,214,146	$568,685,860	(76.4%)
Lease Condensate	10,229,814	29,515,421	(4.0%)
Gas	1,142,255,817	146,199,146	(19.6%)
		744,400,427	

(Exs. 14, 16.)

Geology of Area

The Other Southwest Area is geologically heterogeneous, with little homogeneity involving natural-gas production or the geologic circumstances under which natural gas is found and produced. (9:935; 14:2050.)

The major structural feature is the Ouachita Front, which divides the area into two major geological segments. (9:938.) From northeastern Mississippi the front extends in an arc northwestward into Arkansas, thence westward and southwestward through eastern and southern Oklahoma, thence southward and southwestward into the Big Bend area of west Texas. The oil and natural-gas production northward and westward from the Ouachita Front is from rocks of the Paleozoic era, whereas southward and eastward from the front all significant production is from rocks of the younger Mesozoic and Cenozoic eras.

The Paleozoic rocks which produce oil and natural gas range from Permian to Ordovicion, the Mesozoic production is from Cretaceous and Jurassic rocks; and the Cenozoic production, from Tertiary rocks. The Paleozoic reservoirs are generally

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characterized by inferior porosity and permeability; whereas the porosities and permeabilities of the Mesozoic Cretaceous and Jurassic, and the Cenozoic Tertiary, rocks are generally much better than in the Paleozoic. (9:938-40.)

In the northern or Paleozoic segment, there are a number of major uplifts and basins. The Ouachita uplift dominates the western portion of south central Arkansas and the adjoining portion of Oklahoma; the Ozark uplift lies in northern Arkansas and adjoining portions of Oklahoma extending into Missouri. Between these two uplifts is the Arkoma Basin, located generally in the Arkansas Valley. Westward from the Ozark Mountains and the Arkoma Basin is the Central Oklahoma platform and northeastern Oklahoma shelf of central and northestern Oklahoma. Westward from the Ouachita Mountains are the Arbuckle and Wichita-Criner uplifts. South of the Arbuckle Uplift is the Ardmore Basin, in south central Oklahoma and northeast Texas. The Ardmore Basin is separated from the Marietta-Sherman Basin by an arm of the Wichita-Criner uplift.

The Marietta-Sherman Basin extends from Oklahoma into Grayson County, Texas, in District 9. Westward from the Marietta-Sherman Basin is the Muenster Arch. This arch plunges southestward across Jefferson County, Oklahoma, into portions of Montague, Cooke, Grayson, Denten, and Collin Counties, Texas, in District 9. (9:942-44; Ex. 1. Map 3.) Two other major geological features

are common to both Texas District 9 and adjacent Oklahoma; namely, the Hardeman Syncline and the Red River Arch. (Ex. 26; Ex. 11, Map 3.) "Other" Oklahoma (except the southeastern part) and Texas District 9 (except a narrow strip on its eastern border) lie in the Osage Plains. (9:936.)

A major structural element in west-central Texas is the northward plunge of the Bend Arch. Only the northern part of this arch is in the Other Southwest Area. The Fort Worth Basin lies between the Bend Arch and the Muenster Arch; and, except its western flant, is within the Other Southwest Area. The Fort Worth Basin and the Muenster Arch disappear under the Ouachita structural front.

In the southeastern portion of the Paleozoic segment is the Black Warrior Basin of northeastern Mississippi and adjoining Alabama. Westward, Paleozoic rocks are buried under thick younger sediments. (9:943-44; Ex. 1, Map 3.)

The crystalline-rock basement of the Paleozoic is highly irregular. It ranges from basement at the surface in the Witchita and Arbuckle uplifts to a depth of at least 36,000 feet in the trough of the Arkoma Basin. (9:958.)

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Eighty-two "major" fields have been discovered in the United States (fields producing nonassociated or associated gas having recoverable reserves of more than one trillion cubic feet). Of these, fifteen are located in the Other Southwest Area. (9:945-47.)

In the southern or Cenozoic-Mesozoic segment there are two major embayments or basinal areas—the Mississippi on the east, extending from the coast into northeastern Arkansas; and the East Texas Embayment on the west.

They are separated by two major uplifts, the Sabine Uplift eastward from the deeper portion of the East Texas Basin; and the Monroe Uplift eastward on the western side of the Mississippi Embayment. Within these embayments and southward from the Sabine and Monroe uplifts are three interior salt dome basins. The salt domes are located in east Texas, southwestward from the Sabine Uplift; in northern Louisiana, southeastward from the Sabine Uplift, and in Mississippi southeastward from the Monroe Uplift. Many of the accumulations of gas and oil in the embayments are controlled by arches in overlying rocks resulting from deep-seated upswellings of salt.

An important fault system in Cenozoic and Mesozic rocks extends northward along the western rim of the East Texas Embayment. This is the Mexia-Talco fault zone which continues northward through Texas, eastward through southern Arkansas, and probably eastward across the Mississippi Embayment and southeastward through Mississippi into Alabama, where it is known as the Pickens-Pollard fault zone. Major oil and gas fields are associated with this fault zone. (9:941-42.) In southeastern Arkansas is the small Desha Basin. (9:961; 15:1175.)

In the Cenozoic-Mesozoic segment, rocks generally dip and progressively become deeper southward toward the Gulf. Depth to the basement increases from somewhat less than 20,00 feet in the northern portion of the segment to more than 32,000 feet along the coast; and, offshore, to over 40,000 feet at water depths of less than 500 feet. (9:958.)

Nine nonassociated major gas fields have been discovered in the Cenozoic-Mesozoic segment; *viz.*, six in north Louisiana, two in east Texas, and one in south Mississippi. (9:947; Ex 1, Map 4.) Discovered in 1916, Monroe, in north Louisiana, is a gas field of the first

magnitude. Carthage Field, in east Texas, was found in 1936. No gas field discovered in the United States since then (with the possible exception of Gomez) is comparable to it in amount of reserves. (9:948.)

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III. RATE OF RETURN

Claimed Necessity for High Return as Incentive for Exploratory Effort

The essence of the respondent producers' argument is that the rates they seek are needed as incentives to induce exploratory effort for gas supplies sufficient to meet the increasing market requirements. The argument was made in prior area rate proceedings.

This argument has a familiar ring. Following the decision of the Supreme Court in 1954 in *Phillips Petroleum Co.* v. *Wisconsin*, 347 U.S. 672, holding that this Commission has jurisdiction under the Natural Gas Act over producer wholesales in interstate commerce, unsuccessful legislation was introduced in Congress to exempt producers from the Act. More than fifteen years ago, in hearings before the House and Senate Committees on the bills, representatives of the producers made the same argument to justify such exemption as the producers are now making to justify the rates which they seek. In the House and Senate hearings, David T. Searls, representative of producer interests, argued that the legislation gave the independent producer "the incentive to undertake the risks and hazards which someone must take in order to insure an adequate supply." (Hearings before the House Committee on Interstate and Foreign Commerce on H. R. 4560, 84th Cong., 1st Sess., March 24, 1955, p. 145; Hearings before the Senate Committee on Interstate and

Foreign Commerce on S. 1853, May 10, 1955, p. 82.) In the Senate hearings, a resolution of the Natural Gas Committee, Independent Petroleum Association of America, declared: ". . . Federal regulation of production of natural gas will inevitably result in diminishing supplies . . . ." (Hearings on S. 1853, May 12, 1955, p. 274.) Use of this argument over the years, under variant situations, weakens its force.

Significantly, at the time of these Congressional hearings, before the Commission had attempted to regulate independent producers, their rates for sales to interstate pipelines in the Other Southwest Area were a weighted average price of 10.2¢ per Mcf. (Ex 60, Sch. 7, sheet 1, col f.) Yet the producers are now claiming that to receive a reasonable return they must have rates in various parts of the Other Southwest Area ranging from at least 16.0¢ to 22.6¢. (Prod. Br., 231, 237.) [5] These rates

would be roughly 60% to 120% higher than the prices the producers voluntarily had in effect when they were protesting the Natural Gas Act being applied to them. This large advance in rates makes their claim suspect and requires that they be tested against producer costs. *Cf. Dayton Power & Light Co.* v. *Public Utilities Commission*, 292 U.S. 290, 311-12; *Federal Power Commission* v. *Interstate Natural Gas Co.*, 336 U.S. 577, 581-82; *Atlantic Refining Co.* v. *Public Service Commission*, 360 U.S. 378, 390-91, 393.

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[5] The following abbreviations are used to denote various briefs: "Prod. Br."—Initial Brief, Principal Producer Group; "Prod. Rep. Br."—Reply Brief, Principal Producer Group; "AGD Br."—Initial Brief, Associated Gas Distributors; "AGD Rep. Br."—Reply Brief, Associated Gas Distributors; "Staff Br."—Initial Staff Brief; "Staff Rep. Br."—Staff Reply Brief.

The largest single factor in respondent producers' cost approach is their claim that, for both "flowing gas" and "new gas-well gas," a rate of return of 16% on net book investment is justified. (Prod. Br., 187-88, 191.) The Examiner is of the considered view, and finds, that this claim is unreasonable; and that a fair, adequate, and reasonable rate of return, both for flowing gas and new gas-well gas, is 10½%. (See *infra*, pp. 116-17 for explanation of rate structure with separate rate ceilings for new gas-well gas and flowing gas.)

The producers' argument that there is an "urgent necessity of providing greater profit incentive" to encourage exploration for and development of new gas supplies (*Ibid.*, 191), is divided into two parts. The first part pertains to the national supply and the second part, to the supply in the Other Southwest Area.

National Gas Supply. The producers' expert witness on gas supplies, Radford L. Schantz, expressly concedes that he is "not questioning the level of ultimate gas supply." He cites a study of the Potential Gas Committee of the Independent Natural Gas Association of America, as of December 31, 1966, that there remains over and above the 286 trillion cubic feet of proved gas reserves in the continental United States, an additional 300 trillion cubic feet of "probable supply," "210 trillion cubic feet of possible supply," and 180 trillion cubic feet of "speculative supply." (9:1067.) The position of the witness and of the respondent producers is that the additional incentives are needed to increase "the relative near-term future finding rates for natural-gas reserves." (Prod. Br., 24.)

Schantz has made three supply-demand studies and describes the results of Study One as "quite startling." (9:1063.)

In this study, he estimates that the annual supply of natural gas in the United States for the entire period 1968 to 1980 will remain constant; *i.e.*, a static figure of 19,515 billion cubic feet derived by computing the average new supply for the 12-year period 1956 to 1967. He compares this figure with the future demand (net production) forecast by the Future Requirements Committee, which progressively increases from 18,960 billion cubic feet in 1968 to 26,900 billion cubic feet in 1980. Thereby he shows net production exceeding new supply by 1969 and each year thereafter through 1980. (Ex. 70, p. 15.) He refers to the year when the net production first exceeds the annual new supply as the "cross-over point." (9:1066.)

In Study Two, Schantz likewise estimates that the annual supply of natural gas from 1968 to 1980 will remain constant. Study Two differs from Study One in that the static figure used is 20,610 billion cubic feet, the average new supply for the three-year period 1965-1967. He compares this figure with the future demand forecast by the Future Requirements Committee, and on this basis shows net production outstripping new supply in the year 1971 and thereafter. (Ex 70, p. 16.)

The Examiner is of the view that the witness' estimate of new supply is unsound; and his use of a constant figure, unjustified. The record shows that the new supply of natural gas exceeded net production in every year from 1946 to 1967, inclusive. (Ex. 70, p. 4.) Furthermore, Schantz's position in these two studies that the annual supply will not increase between 1968 and 1980 is refuted by two recent reports of the U.S. Department of the Interior, Office of Oil and Gas, Items II and III, hereinafter considered.

Schantz's third study adopts a projection of new supply contained in C. L. Moore, Office of Oil and Gas, *Projections of U.S. Petroleum Supply to 1980* (December 1966), Item II herein. This report "projects to 1980 the historic patterns of discovery, development and production of petroleum in the United States. These projections are not forecasts of future supply," but are "guide lines which may be compared with projected requirements." (Item II, Foreword by Onnie P. Lattu, Director, Office of Oil and Gas.) The Moore projections are based on application of the Gompertz curve; the data on gross additions to reserves cover the period 1946 to 1965. (Item II, p. 1.) Unlike the Schantz estimate, Moore projects an increase in "gross additions to proved reserves," or new supply, each year to 1980. (*Ibid.*, p. 22.) Schantz combines the Moore projection of supply with the future demand forecast of the Future Requirements Committee, and is thereby able to reach a result indicating a cross-over in 1973. (Ex. 70, p. 17.) However, the Moore projections do not show a cross-over until 1978 (Item II, p. 22.), and are

guide lines, not forecasts of supply.[6]

[6] Schantz points out that for 1966, Moore's projection of production was too conservative—16 trillion cubic feet, whereas the actual production that year was 17½ trillion cubic feet. (11:1614.) However, Moore notes, "In the discovery projections, accelerated offshore exploration may increase the trend." Moore goes on to say that "Other factors, such as area-pricing for natural gas, may tend to decrease it." (Item II, p. 3.) But Moore, an engineer, does not profess to know how low a rate would have to be set for producer wholesalers in order to decrease the trend.

Attendant upon the receipt of Item II in evidence, the Examiner afforded the producers opportunity to arrange for C. L. Moore to testify in the proceeding, but they did not call him as a witness. (11:1588-89.)

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Presiding Examiner's Initial Decision

On July 1, 1968, the Office of Oil and Gas issued a report, Item III, entitled, *United States Petroleum through 1980*. This authoritative, objective study was prepared and approved by a select group of government officials, geologists, engineers (including petroleum engineers), natural-gas specialists, and economists. The presentation and the findings therein "of the outlook for domestic oil and gas availability over the 15-year period between 1965 and 1980" were made by a Working Task Force, under the general purview of the Energy Policy Staff of the Department of the Interior. (Item III, p. iii.) The members of the Energy Policy Staff and the Working Task Force are: "*Energy Policy Staff*—William T. Pecora, Chairman, Director U.S. Geological Survey; Newcomb B. Bennett, Jr., Assistant Commissioner, Bureau of Reclamation; Milton Chase, Staff Assistant, Office of Assistant Secretary—Water & Power; William E. S. Flory, Director, Office of Minerals and Solid Fuels; George Fumich, Jr., Director, Office of Coal Research; Onnie P. Lattu, Director, Office of Oil and Gas; Vincent E. McKelvey, Research Geologist, U.S. Geological Survey; J. M. Morgan, General Engineer, Office of Assistant Secretary—Water & Power; James C. Rettie, Assistant Director, Program Support Staff; Paul Zinner, Assistant Director—Planning, Bureau of Mines; Harry Perry, Secretary, Mineral Resources Research Advisor to Assistant Secretary—Mineral Resources. *Working Task Force*—Onnie P. Lattu, Chairman, Director, Office of Oil and Gas; C. Marvin Case, Foreign Programming Specialist, Office of Oil and Gas; Neil Cochran, Chief, Division of Utilization, Office of Coal Research; Donald Duncan, Geologist, Organic Fuels Branch,

U.S. Geological Survey; William C. Elliott, Jr., Chief Division of Petroleum, Bureau of Mines; Ferdinand Gagné, Natural Gas Specialist, Office of Oil and Gas (to June 1967); Richard F. Meyer, Domestic Oil Specialist, Office of Oil and Gas; David R. Oliver, Economic Research Specialist, Office of Oil and Gas; John Ricca, Deputy Director, Office of Oil and Gas; J. J. Simmons, III, Assistant Director, Office of Oil and Gas; Ralph E. Williams, Secretary, Special Assistant to Director, Office of Oil and Gas." (*Ibid.*, p. ii.)

On the basis of *United States Petroleum through 1980*, the reasonable and justifiable conclusion is that an adequate supply of proved reserves will be acquired to meet demands through 1980. As true in any projection, this report is necessarily based on assumptions. One assumption is that "uncontrolled inflation or deflation will be avoided." Another is that "pollution abatement measures" will have "nominal" effects on the "consumption of hydrocarbon fuels." (Item 3, p. 1.) Within these and other necessary limitations,[7] the report furnishes the best estimate by the Office of Oil and Gas of the supply demand relationship for natural gas through 1980. According to the estimate, an adequate supply of natural gas for such period should be realized. The Examiner is of the view and finds that such estimate is reasonable, sound and valid; and is the best opinon available upon the question.

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[7] Other assumptions are that there will be "no large scale war," "no major depression," and no "real" price changes; "*e.g.*, the price of coal as related to the price of fuel oil or gas with which it competes, and to the general wholesale price index of which it is a part"; "population to increase at 1.3% annually"; "real gross national product to grow at four percent annually"; and "technological advances will be gradual and evolutionary.' (*Ibid.*)

After describing the petroleum resources base, the report, Item III, reaches this conclusion:

> "The rate at which these resources will be discovered, developed, and produced will be determined by individual entrepreneurs, large and small, as they respond to opportunities for profit which they believe to exist in these operations. The preceeding description of the petroleum resource base merely indicates that the amounts of oil and gas that are physically present beneath the surface are very large indeed—enough to supply any conceivable need for a period running well beyond that

> contemplated by this survey. They can be made available to the nation—but at a cost which may be more, *or less*, than that experienced in the past . . . ." (underscoring added.) (*Ibid.*, p. 12.)

The Examiner so finds and concludes.

At page 24, the report makes this assessment of the results of gas exploration in the period 1946 to 1966: "Exploratory effort is down but results have held up well as findings per well improve." The Examiner so finds, upon the basis of the report and other evidence in the record to the same effect.

Total natural-gas requirements for the period 1966-1980 are estimated in the report at 310 trillion cubic feet, of which approximately 302 trillion cubic feet will be supplied by domestic production. (*Ibid.*,) p. 21.) The Examiner finds that these estimates of requirements are reasonable and sound.

On the question as to what is a proper natural-gas reserves-to-production ratio, the report offers no opinion, other than saying that a ratio of 11.9 to 1 would ap-

pear to be too low. However, the publication contains these observations:

> "Just how far the ratio will be permitted to decline from the current 15.7 to 1 will be determined by the requirements for pipeline reserves imposed upon gas pipelines by regulatory agencies and investors. At what point the combined effect of these requirements upon individual companies will create a floor under the ratio of reserves to production cannot readily be determined."

"On the arbitrary assumption that a minimum requirement of 15 to 1 will constitute the 'floor,'" the report proceeds to give these natural-gas requirements figures: Over the 15-year period between 1965 and 1980, there will be a requirement for gross additions to proved reserves of 376 trillion cubic feet; and required additions in the terminal year 1980 will be 28.7 trillion cubic feet. (*Ibid.*,) p. 21.)

The report makes these significant findings respecting gas reserves and production:

> "Over the period from 1946 to the present [*i.e.*, 1967], additions to proved reserves indicate an anual rate of increase of 2.5 percent, obtained by comparing the mean additions of the earliest and the latest 5-year periods (1946-50 vs 1963-67). The average annual increase over the most recent 5-year period, ended in 1967, was at a

> rate of 2.4 percent, suggesting that the longer term growth trend is still being well sustained. Assuming that this slow decline in growth rate may continue through the period ended in 1980, so that an average annual increase of 2.2 percent is real-

ized, gross additions for the period 1965-1980 would reach 383 trillion cubic feet, with additions in the terminal year of 29.8 trillion cubic feet. Given the encouraging results of gas exploration, particularly in the recent past, the acquisition of proved reserves of this order seems well within the industry's capabilities." (*Ibid.*, pp. 24-25.)

The Examiner so finds and concludes.

It will be seen that the 383 trillion cubic feet of new supply over the period 1965-1980 exceeds the Office of Oil and Gas estimate of domestic production over that period, 302 trillion cubic feet. In other words, the Office of Oil and Gas anticipates an excess of supply over production through 1980. The Examiner shares this view, observing, however, that in any one year, an excess of production relative to new supply may occur.[8]

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[8] The 1968 report of the Committee on Natural Gas Reserves of the American Gas Association, issued in May 1969 (after the conclusion of the hearing), shows a sharp decline in new supply in relation to production. The new supply in 1968 was only 18,772 MMMcf, whereas net production was 19,479 MMMcf. (American Gas Association, Inc., etc., *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada* as of December 31, 1968, p. 126; figures converted from 14.73 psia to 14.65 psia. This and like reports for other years are hereinafter cited as *AGA Reserves Report*.) In the previous year, new supply was 21,923 MMMcf and net production, 18,481 MMMcf. (*AGA Reserves Report, 1967*, p. 131; figures converted from 14.73 psia to 14.65 psia.) Hence, for the first time since 1946, when AGA began reporting statistics on proved gas reserves, total U.S. net production exceeded new supply; and a cross-over in the supply-demand relationship took place. In the Examiner's opinion, this happening is an anomaly, a temporary situation; and soon annual new supply should again continue to exceed annual net production. This opinion is justified by the Moore report and *United States Petroleum through 1980*.

Other evidence supports this opinion. Speaking of declines and increases in annual new supply in relation to net production, as a measure of probabilities for the future, producer witness Dr. J. Rhodes Foster said:

[Footnote continued on page 79]

It has been noted that the required gross additions to proved reserves during the 1966-1980 period of 376 trillion cubic feet are at an assumed reserves-to-production ratio of 15 to 1. *A fortiori* it must be true that the industry can bring forth supplies which would result in maintaining a lower reserves-to-production ratio. The Office of Oil and Gas has found, and the Examiner finds, that the industry can achieve a task more difficult than is necessary under prior Commission holdings in area rate proceedings. *Southern Louisiana*, Opinion 546, mimeo., 15; *Permian*, 34 F.P.C., at 184-85.

It is apparent that a substantial margin remains for consumption of natural gas in control of environmental pollution, if use of gas for such purpose becomes necessary.

It has been noted that *United States Petroleum through 1980* was released by the Department of the Interior on July 1, 1968. On July 24 following, during

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[8] [Continued]

". . . there is an inherent instability in reserve data.

". . . you really can't reach reliable conclusion by looking to data for one year." (49:5187, 5188.)

Twice before, in 1954 and 1960, there was a sharp decline in new supply as compared with net production, only to have new supply rebound the following year. Thus, in 1953 new supply was 20,453 MMMcf and net production, 9,239 MMMcf. In 1954, new supply was only 9,599 MMMcf and net production, 9,427 MMMcf—a situation close to a cross-over. But in 1955, new supply was up to 22,017 MMMcf, and net production, 10,118 MMMcf.

In 1959, new supply was 20,734 MMMcf and net production, 12,441 MMMcf. In 1960, new suply dropped to 13,970 MMMcf, close to a cross-over point, since net production was 13,090 MMMcf. But in 1961, new supply rebounded to 17,260 MMMcf, whereas net production was 13,452 MMMcf. (*AGA Reserve Reports* for the years in question.)

cross-examination of Schantz testifying in rebuttal, the report was produced in the hearing for the first time; and the witness was asked questions about the projection therein of gross additions for the 1965-1980 period. Schantz took the position that he did not believe "those terminal figures" would be reached" based on the existing incentive and well-drilling activity structure"; that the report

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"assumes, in my judgment, . . . that there will be sufficient incentive and well-drilling activity to bring forth these new supplies." (52:5630-31.)

The next day the report, offered by the staff, was received in evidence as Item III. The producer group asked for opportunity to controvert the report, and "to obtain . . . clarification [of it] through those parties who prepared the report." (52:5633; 53:5700.) Staff counsel stated, "I would have no objection if the producers, or any of them, would wish to rebut any of the statements, conclusions, assumptions or what-have-you, in the report." (53:5701-02) The Examiner ruled, ". . . the producers, or any intervenor in the case, will be afforded the opportunity to produce evidence respecting this document. . . . The producers will have the month of August in which to prepare whatever evidence they may see fit to prepare, or arrange for a witness or witnesses to be present, because under the schedule which has been outlined we are going to take most of August as a vacation month, and we wlll resume early in September." (53:5705.)

To the end of producing evidence respecting Item III, counsel for Humble had a conference with Admiral Lattu, Director of the Office of Oil and Gas and Chairman of the Task Force, about it. (59:6359.) Shortly thereafter, on August 12, Humble's counsel addressed a

letter to Admiral Lattu with reference to the instant proceeding and the "Need for Clarification from Department of Interior of Document Entitled 'United States Petroleum Through 1980.'" The letter recited:

> "One of the factors which the Commission will consider in reaching its decision will be the adequacy or inadequacy of future gas supplies to meet the projected demand for natural gas in the United States.
>
> ". . . rather than subpoenaing a witness, we would, if possible, prefer to handle the clarification through correspondence with the Office of Oil and Gas.
>
> "We recognize that this report was not prepared for the purpose of being used as evidence in an administrative proceeding, ...
>
> ". . . . in referring [in the paragraph at pages 24 and 25] to a projection of reserves addditions from 1965 to 1980 and projected additions in 1980 of 29.8 trillion cubic feet [the report]states, '. . . the acquisition of projected reserves of this order seems well within the industry's capabilities.'

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> "Did the Department of Interior in making this projection find it necessary to make an assumption as to the gas price in cents per Mcf required to induce the necessary exploratory effort to discover reserves of approximately 30 trillion cubic feet in 1980?" (Ex: 101.)

In his reply, Admiral Lattu states in effect that the Department did not make an assumpiton as to the price of gas required to induce the necessary exploratory effort. Nor does he say that the report was not prepared for use as evidence in an administrative proceeding. Instead, the reply of the Director states:

> "The price of gas is only one of the factors which may affect 'the industry's capabilities.' Some other factors include the cost of the industry's inputs, the state of its technology, the location, reservoir size, and overall magnitude of remaining undiscovered resources, and industry's fortune and acumen in finding them. Our analysis in the quoted paragraph did not attach specific values to any of these factors but reflected our implicit judgment of their composite relationship." (Ex. 100.)

Thus Schantz's supposition, that the Office of Oil and Gas in making its projections to 1980 assumed a higher price for gas than the existing incentive, is erroneous.

Adducing rebutting evidence, Schantz found fault with *United States Petroleum through 1980* in that at page 21, domestic production is reported to be 15,610 billion cubic feet for 1965, whereas the American Gas Association reports 1965 net production at 16,252 billion cubic feet. The 15,610 billion cubic feet was a figure used by the Office of Oil and Gas to develop a trend in estimating the requirement for gross additions to reserves over the 1966-1980 period. The producer witness recognized that the 15,610 billion cubic feet must have been a preliminary figure. (59:6365.) The small difference between the preliminary figure and the actual figure is unimportant.

Other evidence supplements the showing in Item III that supplies of natural gas stand to be adequate through 1980. The most detailed evidence pertains to Southern Louisiana. This area has become preeminent as a source of gas supplies for interstate pipeline companies. An analysis of gas supply data submitted by 24 major pipeline companies to the Commission for 1963-64 shows that the Southern Louisiana area accounts for about 37% of the total 1967 year-end reserves (including warranty gas), and 36% of the total production, reported by these

companies. The next largest gas supply area for these pipelines, Hugoton-Anadarko, accounted for only about 18% of total reserves and 21% of total production.

Total natural-gas production in Southern Louisiana has almost doubled since 1960. As of 1966, over 70% of the 4.6 trillion cubic feet of production was onshore, but production offshore has been increasing at a substantially greater rate. Since 1962, the onshore production has been increasing annually at a rate of from 7.2% to 11.9% (Ex. 94, p. 1); whereas from 1965 to 1966, gas produced from the offshore areas (federal and state) increased by over 30%. (*Ibid.*) Dr. Gordon I. Atwater, a geologist of outstanding ability, made a careful study for another proceeding in which he estimated the total recoverable gas reserves of the Louisiana offshore water bottoms at 75,000 billion cubic feet, of which 21,673 billion cubic feet had been dedicated to interstate commerce by February 1966. (58:6203-04.)

New discoveries of natural gas in Southern Louisiana are increasing. In 1966, there were 29 new discoveries, of which 17 were in the offshore segment. Both figures are the highest for any year in the period 1960-1966. Exploratory drilling is also on the increase, particularly in the offshore region. (Ex. 94, p. 9; Ex. 9, pp. 372, 375.)

The staff introduced an exhibit which lists 18 pipeline applications filed in 1968 seeking authorization for construction of offshore Louisiana facilities. The proposed facilities are to be constructed at an estimated cost of approximately $270 million; have a total combined capacity of about 2.8 million Mcf per day; and involve total estimated proved offshore Louisiana reserves dedicated to the pipeline companies of approximately 7,921.9 million Mcf. (60:6390; Ex. 95, pp. 1, 15.) Subsequent to

the preparation of this exhibit, eight more certificate applications were filed in 1968 for the construction in the Southern Louisiana offshore segment involving a total amount of proposed construction of about $277 million. Other evidence introduced by the staff shows that there is presently a large number of shut-in gas wells in offshore Louisiana.

Taking up the Permian Basin, the evidence establishes that from 1958 through 1966, the number of gas wells and exploratory gas-well footage increased. (Ex. 9, p. 527, cols. e and f.) In the same period, total gas-well drilling—exploratory and development—increased: total gas wells increased from 147 in 1958 to 259 in 1966; gas-well footage increased from 1.1 million feet in 1958 to 2.2 million feet in 1966. (Ex. 9, p. 532, cols. e and f; Staff Br., p. 104.) The 1967 ratio of new supply to net production was 2.6 to 1. (Ex. 70, p. 25.)

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In the Anadarko Basin, exploratory footage drilled in the Oklahoma Anadarko area from 1958 through 1966 increased substantially (Ex. 9, p. 383, col. o); and total footage (exploratory and developmental) has more than doubled. (Ex. 9, p. 488, col. o.) There has been a decline in exploratory footage drilled in the Oklahoma Panhandle area; total footage in that area (exploratory and developmental) has remained relatively constant. (Ex. 9, pp. 382, 385; p. 487, col. o.)

Phillips has drilled a number of deep wells in the Anadarko Basin, and the results for the most part have been disappointing. (57:6069 *et seq.*) However, Phillips continues to hold to the opinion that "the potential . . . is pretty high in the deep parts of the Anadarko basin." (58:6259.)

Presiding Examiner's Initial Decision

The Examiner finds and concludes that, through 1980, the producers should produce as much gas as the markets can take.

Gas Supply in Other Southwest Area. Contrasting with the national picture, in the Other Southwest Area since 1956, new gas supply, net production, and exploratory drilling have been relatively stable. The table below sets out the figures:

New Supply and Net Production (Billion Cublic Feet at 14.65 psia) and Number of Exploratory Wells Other Southwest Area

	New Supply[a]	Net Production[a]	Exploratory Wells[b]		
			Oil	Gas	Dry
1956	1,594	2,133	—	—	—
1957	2,146	2,342	—	—	—
1958	3,154	2,205	211	76	1,842
1959	2,037	2,275	179	55	1,797
1960	2,222	2,254	208	78	1,663
1961	2,114	2,124	129	60	1,412
1962	2,196	2,080	145	66	1,281
1963	2,655	2,260	159	49	1,397
1964	2,882	2,215	173	67	1,445
1965	2,270	2,183	143	37	1,368
1966	2,105	2,298	204	89	1,425
1967	1,117	2,196	—	—	—

[a]Ex. 4, p. 27; Ex. 70, p. 27.

[b]Ex. 9, p. 521.

The principal producer group point out that the reserves-to-production ratio has hovered around 12 to 1; production has not increased; and interstate markets historically served by the area have obtained incremental new deliveries from other producing areas, such as Louisiana. They contend that the rates fixed should contain special noncost allowances as incentives "so that increased new supplies and net production in the Other Southwest Area will enable that area to make a meaningful contribution towards the substantial future demand for gas throughout the United States." (Prod. Br., 26-27.) Similarly AGD argues that there is a need to provide an inducement for added exploratory efforts in the area, and hence the rates for new gas should be fixed at "a reasonable margin above the average new gas cost." (AGD Br., 44-45.) In similar vein, the pipeline purchaser group argue that "the producers must be given the incentive greatly to increase their exploratory efforts." (Pipeline Br., 6-7.)

These arguments beg the question. They assume that the rates which respondent producers seek, and also those which AGD recommend, will cause the producers to explore for meaningful new supplies of gas. The Examiner disagrees with this assumption.

In conformity with *Permian*, the Examiner prescribes a rate structure consisting of one set of ceiling rates for "new gas-well gas" and another set of ceiling rates for "flowing gas" or all other gas. In the context of this dual-pricing method, the producer group advocate rates with those for new gas-well gas containing the aforementioned noncost allowances.[9]

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[9] TIPRO recommends a single area rate in the range of 18¢ and 21¢ per Mcf, as an incentive to search for new supplies and to make

The new-gas ceiling rates herein prescribed and those which the producer group recommend cannot be stated on a fully compatible basis. The rates proposed by the producers would be applicable to sales of gas without regard to quality or delivery point, with higher rates required (at unstated levels) should a system of mandatory delivery conditions be adopted. (Prod. Br., 237.) The ceiling rates herein prescribed are applicable to

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pipeline quality gas. They include cost allowances for gathering and quality improvement, with the qualification that deductions from the ceiling for failure to meet certain quality standards are left to the parties to negotiate. Hence, the rates prescribed are not specific with respect to deductions applicable to gas of less than pipeline quality. The most nearly comparable basis on which the new-gas ceiling rates established by this decision and those recommended by the producer group is to make a comparison of the new-gas ceiling rates herein established for both gathered and ungathered gas, with the producer group's new-gas ceiling rates. Such rates (¢/Mcf) are set out below:

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interstate sales, and as a source of more internally generated funds. The proposal for a single rate must be rejected. See *infra*, p. 41. The treatment herein on the question of incentive in response to the claims of the principal producer group and AGD serve to answer TIPRO upon such question as well. Nor is the Examiner persuaded that a rate to provide more internally generated funds is warranted under the "just and reasonable" standard of Section 4(a) of the Act.

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	Examiner		Producers
	Ungathered	Gathered	
Other Oklahoma	16.9	18.4	18.0
North Arkansas	16.3	17.8	18.0
Texas Districts 5 and 6	17.1	18.1	18.0
Texas District 9	17.2	18.7	18.0
South Arkansas	16.25	17.25	18.0
Mississippi (onshore)	17.0 [a]	18.25[a]	22.6[a]
5 Louisiana Parishes Adjacent to Mississippi [b]	18.6 [a]	18.25[a]	22.6[a]
Remaining North Louisiana	18.6 [a]	19.6 [a]	20.5[a]
4 Alabama Counties [c]	17.0 [a]	18.25[a]	22.6[a]

[a] These rates are stated at a pressure base of 15.025 psia. All other rates are stated at 14.65 psia.

[b] Catahoula, Concordia, Franklin, LaSalle, and Tensas Parishes.

[c] Marion, Fayette, Lamar, and Pickens Counties.

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Looking solely to a comparison of rates based on the rates herein prescribed for ungathered gas, it will be seen that the spread between the prescribed rates and those proposed by the producers is from 1.70¢ per Mcf to less than a cent for other Oklahoma, north Arkansas, and Texas Railroad Districts Nos. 5, 6, and 9. In south Arkansas and north Louisiana (excluding the five parishes adjacent to Mississippi), the spread is 1.75¢ and 1.9¢, respectively. Finally, the largest differences are for Mississippi (onshore), the four Alabama counties, and the five Louisiana parishes adjacent to Mississippi. For Mississippi and the Alabama counties, the spread is 5.6¢; and for the five Louisiana parishes, 4.0¢.

The rates advocated by AGD are indeterminate. They are geared to what may be allowed in other area rate

proceedings. AGD's premise is that new gas prices in various subareas of the Other Southwest Area should not be less than those applicable in adjacent areas covered by other area rate proceedings. Thus, their rate design witness, Charles H. Frazier, stated that the north Louisiana and Mississippi prices should be set at a level not lower than that applicable in south Louisiana. The top rate for new gas in south Louisiana that the Commission has come up with so far is 20¢. Frazier recommended that prices in east Texas (Districts 5 and 6) be not lower than that applicable in District 3 (17.4¢) for ungathered gas under the Examiner's initial decision in *Texas Gulf Coast*. The same procedure would be followed in designing ceiling rates for Arkansas and other Oklahoma. Their figure would lie between the rates herein fixed and the producers' proposed rates for the Alabama counties, Mississippi, north Louisiana, and Texas Districts 5 and 6.

Remember that the only representatives of consumers who have participated in the hearing or the briefing are the staff of the Federal Power Commission. AGD are acting for themselves. The pipeline group, too, are acting in their own interests—and one-half of this group own extensive production properties either directly or through affiliates.

The arguments of the producer group, the pipeline group, and AGD do not take into account the reason for the static condition of exploration and new supplies in this area. The evidence shows that this reason is that the major producers have primarily sought gas in other provinces, which are more attractive to them. Frazier himself testified, and the Examiner finds that "the producers have elected to spend most of their exploration and development dollars outside the Other Southwest Area." (50:5401.) Many companies have closed explora-

tion offices which had existed for years in various districts, such as Shawnee and Ardmore, Oklahoma; Wichita Falls, and Tyler; Texas; Shreveport,

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Louisiana; and Jackson, Mississippi. Population of geologists and geophysicists in these districts has also fallen. (9:955.)

Testifying on behalf of the producers, B. W. Beebe, a geologist whose principal business is directing exploration for and development of gas and oil, said: "The incentive is to look in the large areas that are relatively unexplored. . . . There is a limit to the amount of money that any company has to spend, and they will spend it where they think they will find the largest reward." (14:2047.) And further, "In a relatively unexplored area, obviously such as off-shore Louisiana, we find a number of large fields. In the Delaware Basin we found some large fields." (15:2097.) And further, "I think it is pretty generally recognized in the industry that most of the large companies have pulled out of the central part of the United States as far as budget is concerned. Many offices have been closed. And from the prices paid in offshore California they find offshore California more interesting; and they find Alaska more interesting; and they find southern offshore Louisiana, particularly, more interesting." (15:2143.) "Money is being spent where they think they can find large reserves, ..." (15:2144.) The Examiner so finds.

Rich deposits of oil and gas in other provinces, notably the Texas Gulf Coast and other parts of the Permian Basin, for more than a decade have been the focuses of major exploration and development. These endeavors are continuing at an augmented pace. Thus, on June 13,

1967, large producers purchased 158 blocks of federal leases in offshore Louisiana for which they paid the federal government $510,079,178 in bonuses. (Ex. 99-A, Sch. 4; 57:6053.) On February 6, 1968, large producers purchased federal leases in offshore California for which they paid the federal government $602,719,262 in bonuses. (Ex. 99-A, Sch. 7; 57:6055.) On May 21, 1968, large producers purchased federal leases in offshore Texas for which they paid the federal government $595,870,355 in bonuses. (Ex. 99, Sch. 8; 57:6057-58.)

The Examiner is of the view, and finds, that the spread between the rates prescribed in this decision and those proposed by the producer group and AGD would not suffice to cause the large companies who have "pulled out of" major exploratory activity in the Other Southwest Area to open their closed offices and reengage in major exploration. The record justifies the conclusion that the reserve potential in this area, as viewed by the industry itself, is insufficiently attractive for such result to ensue. Since 1950, no major field has been discovered in the area; nor, according to Beebe, has much been accomplished in finding "sizable" fields. (9:948; 15:2097.)

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More particularly, taking up the portions of the area where the spread under the prescribed rates and the producers' proposed rates is from 1.70¢ to less than a cent: Northeastern Oklahoma northward and westward from the Arkoma Basin, including the Shelf and Central Oklahoma Platform, which formerly had largely oil production, is virtually drilled out. The remaining potential for gas discovery is of no importance. (9:969-70.) In north Arkansas, including the Arkansas portion of the Arkoma Basin, gas has not attracted large interstate

markets because of lack of large fields; hence most of the gas is sold locally. (9:949-50, 965, 967, 2131; Ex. 52, Sch. 5.) The complex, tightly folded Ouachita Uplift is of little or no interest in relation to oil and gas; the potential is completely speculative. (9:969, 1173.)

In the Ardmore and Marietta-Sherman basins of Oklahoma, several gas discoveries have been made, but the fields are not large and the reserves are only fair. A good potential exists for additional discoveries of this type. The remainder of southern Oklahoma southward and westward from the Meunster Arch and northward from the Red River Arch of Texas offers a poor potential for natural-gas discoveries. (9:970.) Manifestly these localities will not attract major exploration.

In the late 1950's, major exploration and development of gas deposits in the Oklahoma portion of the Arkoma Basin began; and have continued as the most active portion of the Paleozoic segment. (9:945, 950, 965.) Several large gas discoveries in the deeper Arkoma Basin have been made. (9:956.)

In north Texas, major exploration and development of gas deposits in the Fort Worth Basin began after World War II. (9:950.) Despite its relatively small area and volume, this basin has numerous natural-gas fields. One of these, the Boonsville Field, was a major discovery. (9:971.)

Beebe testified that "both the Arkoma and Fort Worth basins offer excellent prospects for additional major natural-gas discoveries in Pennsylvanian beds now producing in both areas. The possibilities in the pre-Pennsylvanian are somewhat more speculative, but there is ample evidence that they merit prospecting." There are large virgin areas in both basins. (9:974.) Also, in his judgment, "the deeper part of the Fort Worth basin . . . is a gas province." (15:2141.)

The Examiner agrees with the foregoing testimony except the term, "excellent prospects." The Examiner does not question the

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opinion of the distinguished geologist who gave the testimony. However, the term was manifestly used by the witness in a relative sense; *e.g.*, as compared with a region of little or no prospects. The prospects of the Arkoma and Fort Worth Basins are not excellent compared with those of the offshore and other districts where the major operators are now focusing their attention—else these operators would not have pulled out of the Other Southwest Area in major exploratory activity to go to these other places. The Examiner finds the statements of fact in the foregoing quotations to be true. He substitutes "good prospects" for "excellent prospects," and with this modification, finds the opinions expressed to be sound. Clearly, an additional rate allowance of 1.70¢ at most, over and above the rates herein adopted, will not cause the large companies to cut down on their present drilling programs in the other provinces they have found more attractive, and institute deep drilling in a major way in the Arkoma and Fort Worth Basins.

Texas Districts 5 and 6 comprise east Texas as referred to in the testimony. Of these districts, 6 is by far the more important from the standpoint of production. (14:2081.) It should be noted, though, that in 1967 an increase in leasing activity occurred in District 5. (59: 6318-19.) East Texas has been heavily explored in the strata above the Jurassic but has promising potential in the Jurassic. Some 250 new field wildcat and deeper pool tests have been drilled to the Jurassic, resulting in 37 Jurassic discoveries, of which 17 are gas pools. (9: 963.) This degree of interest and activity support the

conclusion that good possibilities for discovery of substantial natural-gas production exist. (9:963.) However, the conclusion is unwarranted that large companies would institute major deep-drilling operations in these districts because of an additional rate allowance of 1.0¢ in the price of gas.

Turning to south Arkansas, where the spread is 1.75¢: In south Arkansas the fields are oil fields. (39:4224.) That part of the State offers little promise for major natural-gas discoveries, except for speculative possibilities eastward from production and in the small Desha Basin in the southeastern portion of the State, which is relatively unexplored and speculative. (9:961, 973.)

Considering next north Louisiana: It has been seen that the producers recommend that gas from five parishes adjacent to Mississippi be accorded the same rate as Mississippi gas. This recommendation is pursuant to their pricing-area proposal that the five Louisiana parishes be included in the Mississippi area instead of northern Louisiana. As hereinafter developed, there is want of evidence in the record to justify such proposal and the Examiner necessarily rejects it. (*Infra*, pp. 93-95.) In

other words, the five parishes are to be accorded the same rates as the remainder of northern Louisiana. In the discussion at this point, in the interest of simplicity the producer recommendation for "Remaining North Louisiana" will be treated as applying to all of northern Louisiana. For northern Louisiana, the spread between the rates herein prescribed and the producer proposal as thus adjusted is 1.9¢.

North Louisiana contains more large gas fields than any other portion of the entire hearing area and has

been the major gas producing region of the Cenozoic-Mesozoic segment. (9:961, 962.) The segment has been heavily explored in the Tertiary and Cretaceous formations. (9:958-59, 972; Ex. 1, Chart 1.) No large discoveries have been made since the end of World War II until 1964, when a field was brought in in the Lower Cretaceous limestone at approximately 8,000 feet with an estimated potential ultimate recovery of 600 Bcf of natural gas. This discovery stimulated exploratory drilling, but no additional discoveries have been made. (9:962.) Average prices paid by pipelines increased from 10.7¢ in 1956 to 15.22¢ in 1966, but annual gas purchases remained fairly constant. (Ex. 60, Sch. 7.) The potential appears to be good. (9:958.) However, the conclusion is unjustified that major exploration would be conducted there because of an additional incentive in the price of gas of 1.9¢.

Next to be considered are Mississippi (onshore) and the four counties in northwest Alabama. In this portion of the Other Southwest Area, the spread between the rates prescribed herein and the producers' and AGD's proposals is 5.6¢. The potential in the Black Warrior Basin of northeast Mississippi and the four Alabama counties is speculative. Sixteen small gas fields have been discovered there since 1909. Of these, half have been abandoned. The basin has been characterized to date by poor reservoir characteristics, small structures, and small producing areas; and remains an unknown quantity. (9:964-65.) The prospects elsewhere in north Mississippi appear to be poor. In the Examiner's view, the excess rate allowance of 5.6¢ reflected in the producers' proposal, as compared with the rate prescribed herein, would provide no greater motivation to conduct large-scale testing in the Black Warrior Basin or other parts of north-

ern Mississippi than would the lesser excess allowances in the Arkoma and Fort Worth Basins.

Taking up central and south Mississippi: In 1930 the Jackson Field in the Mississippi Embayment was an important gas discovery, but this field is now depleted and used for storage. (9:949.) About a half dozen fields south of Jackson—Cretaceous, Tertiary and some Jurassic production—have been important sources of natural gas. (9:959, Ex. 1, Map 4, Chart 1.) The Upper Cretaceous formations which have produced so much gas in

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North Louisiana, generally have been oil-bearing in Mississippi. (9:958-59.)

The evidence shows that producers do not possess the ability to search directionally for gas in central and south Mississippi. The strata having the best potential for production are Jurassic, lying at depths below which the general level of drilling has been conducted. (9:959-60; 972-73.) The evidence establishes that the producers do not have geological knowledge and data upon which to predicate a separate search for natural gas at these depths. No areas in central and south Mississippi have been found which are predominantly gas, and such discoveries as have been made indicate that the predominant hydrocarbon at these depths is oil. By the end of 1966, 19 discoveries had been completed in Jurassic reservoirs; and of these, only 3 were gas. Only five pools contained more than one well. By far the most important field is Bay Springs, an oil field, producing from the Cotton Valley. (Ex. 1, Map 4; 9:960.)

Since directional selectivity of gas is wanting, the position that the proposed additional price allowance will increase new supplies of gas in this part of the Other

Southwest Area is correspondingly weakened. The AGD witness' recommended margin above cost as an inducement for added exploratory efforts was premised upon an ability of producers to search directionally for gas. (50:5398, 5403.) Exploratory oil wells predominate over exploratory gas wells in the Other Southwest Area by a ratio of more than 2½ to 1; and unless the operators have confidence that their exploration in central and south Mississippi will be rewarded by striking gas reservoirs, the spread does not have much meaning or incentive.

Moreover, there are strong indications from exploratory drilling in Mississippi in recent years that the price of 22.6¢ which the producers seek would not result in meaningful increased discoveries of gas. The cost-oriented rate, 17¢, prescribed herein is substantially less than the policy statement price of 21.5¢. The prices realized by producers in Mississippi for sales in interstate commerce reached 20.81¢ in 1960 and remained in excess of 20¢ until 1964. (Ex. 60, Sch. 7, sheet 3.) Yet during the entire period of five years when the prices were near the rate for which the producers contend, only 10 successful exploratory gas wells were drilled in Mississippi. (Ex. 9, p. 75.)

The Examiner finds that the spread of 5.6¢ in the maximum rate herein fixed for Mississippi (onshore) and that proposed by the producer group would not cause producers to engage in exploration in central and south Mississippi in a major way, or significantly different than at present.

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Overall, the Examiner finds and concludes that in all portions of the Other Southwest Area, neither the proposed rates of the producers nor of AGD would result in

meaningful or substantial increases in new supplies above those which will be obtained under the rates fixed herein.

With the operators concentrating their main efforts in the relatively new provinces elsewhere in the United States, including the Continental Shelf, the Delaware-Val Verde Basins, and Alaska, where rich deposits of oil and gas are to be found, it is the view of the Examiner that large increases in new supply and net production in the Other Southwest Area are not reasonably attainable. However, drilling of shallow and medium depth wells (9:963; 14:2086; 15:2125-26, 2142); and a relatively few deep exploratory wells, as in recent years (9:960, 961, 962, 963, 969; 14:2069-70, 2083-84; 15:2116, 2132), will unquestionably continue. It can reasonably be expected that current levels of production will be maintained under the two-price rate structure; and at the new-gas ceiling rates herein fixed, which include a fair rate of return. *Permian*, 34 F.P.C., at 186; *cf. Southern Louisiana*, Opinion 546, mimeo., 14. Also, the federal income tax benefits accorded producers, hereinafter considered, insure continued exploration and production. Attempted artificial stimulation to induce gas finds by the special rate allowances would fail of its objective.

As hereinafter explained (pp. 92-93), prices will not be fixed in this proceeding for offshore Mississippi; so the effect on supply in that segment of proposed prices need not be considered.

Fair Rate of Return

The standards to be employed in fixing a rate of return may vary. *Permian Cases*, 390 U.S., at 806. The familiar criteria of the *Hope* case, quoted in *Permian Cases* at page 790, are "whether 'the return to the equity owner [is] commensurate with returns on investments

in other enterprises having corresponding risks,' and whether the return was 'sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.'" Applied to companies engaged in natural-gas production, such criteria include a supply-inducement function so that the companies can conduct a satisfactory program of exploration and development. *Southern Louisiana*, Opinion No. 546, mimeo., 50; Item A: 77:12,150; 12,153-54. The Examiner is of the view, based on the record in the instant proceeding, that these criteria should govern here. In applying them, the two-price rate structure is to be considered. Also to be taken into account is the effect of federal income-tax benefits enjoyed by producers. *Cities of Lexington, etc., Ky.* v. *Federal Power Commission* (C.A. 4), 295 F.2d 109, 118.

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Dr. Felix I. Shaffner, Supervisory Financial Analyst on the staff of the Commission and head of the Finance Section of its Division of Finance and Statistics, recommended a 10½% rate of return component as part of the area ceiling prices of both new gas-well gas and flowing gas. (Item A: 10:1950.) The Examiner accepts this recommendation as satisfying all of the foregoing criteria.

Since there are no major producers engaged solely in the gas business, Shaffner compiled a group of the major suppliers of oil and gas. As the basis of his recommendation, he took the actual rates of return, from overall earnings, of these companies. (Item A: 10:1956; 87: 13,205.) His compilation is a national group of 35 independent producers, comprised of those which, during the period 1962-66, had annual sales of gas in interstate

commerce exceeding 2 million Mcf, had common stock which was actively traded, and made periodic reports of earnings and financial condition. (Item A: 10:1953.) Twenty-six of the petroleum companies were integrated companies, *i.e.*, producers, refiners, and marketers (of whom three, subsequent to 1962, ceased to exist by reason of acquisition or merger). Nine of the companies were nonintegrated companies; *i.e.*, companies whose revenues were principally from production (of whom two were acquired by other companies subsequent to 1962). (Item A: Ex. 8-J, Sch. 4; Ex. 12, Sch. 3A.) The group of 35 producers include all of the major United States oil and gas companies. (Item A: 10:1953.)

The evidence establishes that during the five-year period 1962-1966, the average rate of return earned on average capitalization of the 45 companies was 9.8%; and the average median rate of return, 9.7%. Shaffner pointed out that the median return has the advantage of eliminating the effect of unduly low and unduly high figures. (46:4818.) The 1962-66 average return of the same companies weighted by the 1966 average capitalization was 10.3%. The 1962-66 median return of the companies weighted by the 1966 average capitalization was 10.2%. (Ex. 12, Schs. 16A, 17A, 18.)

The witness' recommended 10½% rate of return component, in lieu of a figure in the range between 9.7% and 10.3%, made some allowance for possible higher earnings in the future. (*Cf.* Item A: 77:12,168-70.) In view of the earnings experience of the national group of independent producers during the five-year period 1962-1966 and the exploratory programs carried on during such period, it appears that a 10½% rate of return should be sufficient to maintain the industry's credit and continue to attract capital.

This rate of return represents an allowance for common equity of 11.72%, since the senior capital (debt and preferred stock) produces leverage. In other words, because the senior capital funds are employed at a rate of return higher than their cost, the return on the investment of the common stockholders is increased. (Item A: 10:2031.) The higher the ratio of debt in the capitalization, the greater the leverage. In arriving at the equity allowance, under the Commission's settled practice the embedded cost of debt is employed. (Item A: 87:13,179-80.)

The tabulation below shows the derivation of the 11.72%. In this tabulation senior capital have been added together as though each of the companies in the national group of 35 independent producers, in each calculation, was a part of one larger company representing the total. (Item A: 10:2050.)

Capital Ratios and Capital Costs—Overall Rate of Return Allowance on Equity—National Group (1966)

Long Term Debt	16.43%	@	4.58%	=	0.752%
Preferred Stock	.71%	@	5.38%	=	0.038%
					0.790%
Common Equity	82.86%	@	11.72%	=	9.71%
					10.50%

(Ex. 12, Sch. 28A.)

In addition, the record shows that oil and gas companies secure results similar to leverage, in the form of an increased return to the common stockholder, in several ways; *viz.*, (1) by ABC transactions, which are in the nature of debt contracts; (2) by leasing oil and gas acreage instead of owning the property outright;

and (3) by farm-out exploratory programs combined with partial support of the exploratory work of others, whereby a company makes use, for its benefit, of the funds of others, and makes a little money go a long way. (Item A: 10:1964, 2032-34.)

A return on common equity of 11.72% is commensurate with returns to the common stockholder on investments in other business undertakings attended by corresponding risks. Earnings data respecting the 500 largest industrial corporations are compiled annually by *Fortune* (reproduced by the U.S. Census Bureau in the annual *Statistical Abstract of the United States*). (9:1185.) *Fortune's* classification "petroleum refining" includes most of the companies on Shaffner's national group of independent producers. (Item A: 10:2047.) According to the *Fortune* compilation for 1961-1966, the petroleum refining industry achieved a return on equity capital which fell near the middle of the range experienced by some 20 or more industry

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groups comprising the 500 corporations. The average of the medians for petroleum refining was 9.7%; and for all industry, 10.2%. The median of the medians for petroleum refining was 9.3%; and for all industry, 9.8%. (Ex. 12, Sch. 26A.)

Investments in the great majority of *Fortune's* 500 highly successful corporations are more risky than are investments in the companies of significance in the oil and gas industry. Standard & Poor's *Security Owners Stock Guide* "500" stock index, representing in value a substantial proportion of all the stocks listed on the New York Exchange, gives composite investment quality ratings of the 500 stocks covered in its study. (Item A:

10:1997.) Of 18 oil companies in Standard & Poor's composite average, 17 are included in Shaffner's national group of independent producers; and the 18th company, Royal Dutch, is surrogated in the staff witness' group by its subsidiary, Shell Oil. (*Ibid.*, 2004.) Shaffner's analysis of Standard & Poor's quality rating shows that the oil industry stocks are high in the list of the top rated categories. Shaffner gave as his opinion, and the Examiner finds, that on a long-term basis, the investment quality of a stock reflects its investment risk. (Item A: 10: 2005-06.) It follows that a return of 11.72% to the owner of oil- and gas-industry stocks is commensurate with returns on manifold investments in high quality stocks of greater risks.

The producer group point to the returns on the common stock equity of natural-gas pipeline companies for the period 1963-1967, 12.4%; and aver, as was held in *Permian* (34 F.P.C., at 201) and *Southern Louisiana* (Opinion 546, mimeo., 46), that pipelines are a safer investment than gas production. (Prod. Br., 204.) In response, first, the 12.4% cited by the producer group was not the Commission's allowance on equity in prescribing the rates. For a number of years the equity allowances in high-debt pipeline company cases have been from 9% to 11%. *Southern Louisiana*, Opinion 546, mimeo., 50, and cases cited; *Florida Gas Transmission Company*, Opinion 561, mimeo., at 7, 18.[10] The 12.4% is the result of higher earnings after the rates were fixed. Also, this percentage does not reflect the effect of substantial refunds ordered in rate-case settlements subsequent to the publication of the figures for the respective years. (Item A: 87:13,-174-75.) Secondly, in the context of the

[10] In *Cities Service Gas Co.*, Opinion 547, mimeo., 8, the Commission allowed a return on equity of 7.39%; but this was a special situation.

present discussion, the risks of pipeline companies are to be compared with those of integrated producers in their company-wide operations.

The fact that natural-gas production operations are combined with other operations tends to reduce the risk; the risks of separate parts are greater than the risk of the integrated enterprise as a whole. (Item A: 86:13,902; 87:13,200.) The revenues from natural-gas sales to pipeline companies comprise only 2.48% of the gross operating income of the national group of companies. (Ex. 12, Sch. 7A.) As Shaffner observed, ". . . this oil and gas producing industry is a giant industry and an industry of giants." (Item A:87:13,199.) The investment quality of the national group of independent producers is far higher than the investment quality of the pipelines. (Item A: 10:1996-2008; 87:13,198-13,200; Ex. 8-J. Sch. 12.)

Moreover, as hereinafter developed (p. 46), federal income tax benefits accorded oil and gas producers mitigate investor risk.

The producer group complaint that in his recommended rate of return the staff witness did not give weight to the earnings of nonintegrated producers separately, and to the earnings on domestic production operations of integrated companies. They argue that such earnings "are the closest one can come to earnings on activities comparable in risk to the business of jurisdictional gas production." (Prod. Br., 194-97.) On the basis of the evidence in the instant proceeding, this position is invalid.

The Examiner is satisfied, and finds, that nonintegrated producers are an unreliable and unrepresentative sample upon which to measure a fair return for the respondent independent producers. The record shows that the typical oil and gas producer is an integrated com-

pany. (Item A: 79:12,328.) Particularly in recent years, there has been a headlong rush toward integration. (Item A: 10:1958-60; 77:12,139.) Although there are many struggling nonintegrated companies that earn little or nothing, there are few remaining outstanding nonintegrated companies. (Item A: 10:1956, 86:13,123-24.) The disappearance of nonintegrated producers results from sell-outs and mergers (especially mergers with integrated gas and oil companies), in order to produce for the successor company a better balance between the amount of oil produced and the amount refined. This purpose has become a more dominant objective of the petroleum industry in recent years. (9:1187; Item A: 10:1959-61; 77:12,139-40; 79:12,314-15; 79:12,344.) Since the hearing in *Permian* two of the nine nonintegrated companies in the Shaffner

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exhibit have been acquired by integrated companies (Ex. 12, Sch. 3A; Item A: 77:12,153); and of the 13 nonintegrated companies used by producer witness Dr. Walter A. Morton, only 7 remain. (Item A: 111:16,053.)

Two companies in the Shaffner and Morton exhibits, Amerada and Superior, account for more than 50% of the capitalization of Shaffner's nine nonintegrated producers. Amerada is a very high-rate-of-return company, its average return for the period 1962-1966 being 20.4%. Superior is a low-rate-of-return company, its average return for the same period being 5.8%. For the seven Shaffner nonintegrated companies still in existence, the average return weighted by 1966 average capitalization is 12.0%. If either Superior or Amerada should cease to exist, the impact on the average return would be substantial. Elimination of Superior increases the group re-

turn to 14.7%, whereas elimination of Amerada reduces the return to 9.1%. (Ex. 12, Sch. 17A.) Manifestly, the nonintegrated companies of sufficient size to be used at all are too small and too shaky a sample.

The unrepresentativeness of the nonintegrated producers further appears from a study by the First National City Bank of New York of the return on net worth of the companies which the bank includes under "petroleum production and refining," covering the period 1951-1965. This study lists considerably more nonintegrated companies than integrated, and many more non-integrated companies than those contained in the Shaffner national group of independent producers. The study shows that the nonintegrated companies, in net worth and profits, represent only a small portion of the total industry. In the period 1951-1965, earnings and net worth ranged between about 5% and 7% of the total for integrated and nonintegrated companies. Also, the proportion of both earnings and net worth of the nonintegrated companies to the total declined markedly since about 1953. (9:1186-87.)

Clearly, the earnings of nonintegrated companies, separately, are no longer entitled to weight in fixing a rate of return. The only proper use now to be made of these companies is to include those meeting appropriate criteria in a group of integrated and nonintegrated independent producers, as Shaffner did.

Respecting the domestic production operations of integrated companies, there are no earnings figures in the record or elsewhere which are useable in arriving at a rate of return. The evidence shows that the producing department of an integrated company cannot be broken out from the rest of the company in return earned.

When an integrated company transfers oil or gas on its books to one of its other departments, it is dealing with itself. Tax benefits and advantages are derived from showing as large a figure as possible for the earnings of the production department. Thus, the higher the gross income from the producing property, the higher becomes the depletion allowance. The evidence shows that it is standard practice of the integrated companies to transfer oil from the production to the refining departments at posted prices, whereas companies are often able to purchase oil from the integrated producers at discounts from posted prices. The evidence further shows that the partition of earning power in the industry between production and the other branches is essentially an artificial one. Consequently, the reported production department profit figures are unusable as a measure of the earnings of the oil and gas production industry in determining a proper rate of return in costing gas. (Item A: 10:1955; 77:12,114-15; 87:13,145-46; 13,234; 162:22,630-31.)

Therefore, in arriving at the rate of return component, it is necessary to use the overall earnings experience of the independent producers on company-wide operations. It is also appropriate to do so. Shaffner testified that a corporation earns a rate of return on its total operations; that the investor looks at the company as a whole, and hence the earnings of the company as a whole are more relevant than those of any single department. (Item A: 77:12,138.) The Examiner agrees. The testimony has particular force in a proceeding to fix prices for gas, since revenues from gas are such a small part of the revenues of the independent producers.

Furthermore, as developed *infra* (pp. 43-46), large federal-income-tax-loss spillovers from the production

function reduce the taxes of integrated production companies payable on their other functions. Since the earnings of each department of the integrated producers are improved by the production department; it is fitting that the earnings of the companies in their total operations be the basis employed in fixing the return allowance on their sales of natural gas.

The producer group argue that Shaffner erred in treating the earnings of the 35-company composite during the period 1962-1966 as representative of the future. They point out that since 1964 the earnings of the 35-company composite have been on the rise, increasing from 9.6% in 1964 to 10.0% in 1965 and 10.6 in 1966. They note that 10.6% is higher than Shaffner's recommended 10.5% return. (Prod. Br., 200.)

On the other hand, the rate of profits for industry in general declined for the first, second, and third quarters of

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1967 as compared with 1966. A study of the First National City Bank of New York reveals a decline in overall rates of profit for 1967 on net worth for total manufacturing of 5%. (9:1182; 45:4712.) As to 1968, the producer respondents introduced evidence from a monthly letter of such bank, May 1968, that earnings of a number of manufacturing and petroleum companies for the first quarter of 1968 were over for the first quarter of 1967. But the figures in this letter are preliminary, covering less than half the companies to be reported by the bank (45:4722); and are insufficient upon which to base a finding as to the earnings picture for the first quarter of 1968.

The three years 1964-1966 and the single year 1966 are not long enough periods fairly to indicate the probabilities

for the future. To the end of reflecting a representative period as well as relatively current experience, it is Shaffner's policy to use the most recent five-year period of earnings' experience available. At the time of preparation of his testimony, such period was 1962-1966. The Examiner finds this policy to be reasonable. Also it accords with Commission precedent. *Phillips Petroleum Co.*, 24 F.P.C. 537, 571.

In addition, consideration of 1964-1966, or 1966, to the exclusion of the earlier years would not be an evenhanded approach because of the increased rate of profits of the oil and gas industry flowing from the Vietnam conflict. (9:1182.) Shaffner correctly testified, "profits in an abnormal period of economic activity need not be considered as normal and necessary profits in a normal period of economic activity." (45:4719.)

The producer group introduced Exhibit 93, a single-sheet tabulation entitled, "Department of Defense Domestic Procurement of Petroleum Products as a Percentage of Total United States Domestic Demand, 1964 and 1967." Columns (1) and (2), "Deliveries to the Military from U.S. Sources, 1964 and 1967," were based on reports on file with the Department of Defense. Columns (3) and (4), "Total U.S. Domestic Demand, 1964 and 1967," were based on *Minerals Yearbook* and "Monthly Petroleum Statement," Department of the Interior. The initial buildup in Vietnam occurred in 1965, and the tabulation purports to show that Defense Department domestic procurement of petroleum products as a percentage of total U.S. domestic demand was only slightly higher in 1967 than in 1964 (4.8% as opposed to 4.3%). This incomplete and inadequate presentation fails to satisfy the Examiner's mind that the Vietnam conflict has not brought abnormal profits to the petroleum industry. Questions such as these immediately present themselves: Is

Exhibit 93 a forthright presentation? Why does it not show a span of years instead of two years, 1964 and 1967? Do the figures in columns (1) and (2)

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cover deliveries to defense contractors? To what extent did the Vietnam conflict occasion deliveries of petroleum products to industrial concerns and commercial airlines? What were the deliveries in Vietnam of petroleum products produced in the Middle East and other foreign sources by U.S. oil companies and their affiliates? Does not this exhibit, designed to show that the profits of the petroleum industry from the Vietnam conflict have been insignificant (46:4796, 4803, 4805-06, 4807-08), offend common sense?

Furthermore, Exhibit 93 fails to overcome the testimony of Shaffner that:

> ". . . oil typically plays an important part in the carrying on of [wartime] activities." (45:4735.)
>
> "I know that the oil and gas industry has been much more active recently, and . . . the allowables in Texas nearly doubled after the Israeli war.
>
> "There would be, in connection with a wartime program, of course, the greater demand for all kinds of fuel, I would assume, in connection with production in this country of wartime materials as well as the supplying of troops and ships and planes abroad and the possible export of petroleum to allies. So I am simply aware that the economy is in a very overheated state, in part, due to the war, and oil is always one of the first things to feel the effect of wartime activities." (46:4809.)

Note also the statement of the Office of Oil and Gas, speaking of petroleum: "The Armed Forces would be immobilized without it." (Item III, p. xi.)

Rate Structure. The two-price rate structure which the Examiner employs, following *Permian*, provides an incentive to exploration. Generally, the differential between the price for flowing gas and new gas-well gas "which the Commission expects to serve as an incentive is the product of differences in the time periods and geographical areas for which costs were computed." *Permian Cases*, 390 U.S., at 6, 7, 10, n. 27, 43-46. "The inducement to be found in the 'new' gas price is of an inherent nature and is not represented by any sum earmarked for that purpose. The incentive is built into the two-price system." *Permian*, 34 F.P.C., at 186.

Furthermore, in costing new gas-well gas, as part of the system of incentive pricing, there is an allowance herein of 1.17¢ per Mcf, Adjustment for Exploration in Excess of

Production. This large allotment, 37% of the exploration and development expenditures, is provided "to encourage a level of exploratory effort which will continue to provide for findings in excess of production." *Permian*, 34 F.P.C., at 193. In other words, the purpose of and justification for this allotment are for it to constitute an incentive to carry on the search for gas to meet future requirements. The item is a cost, but it is a cost only in the sense that the Commision contemplates that the producers will expend such amount in exploration, which is reasonably calculated to yield gas supplies adequate to maintain an excess of findings over production. By this Adjustment embedded in the rate, the producers recoup from the revenues of current production these contemplated exploratory expenses. Moreover, the Adjustment is geared to a stepped-up pace of exploration in the future. As production increases, so will the dollar amount of the Adjustment.

Federal Income-Tax Benefits—Spillovers—Attraction of Capital. According to the evidence, the oil and gas producers enjoy three principal federal income-tax benefits: (1) the 27½% annual depletion allowance, (2) expensing of all dry-hole expense despite valuable geological information obtained, and (3) expensing of intangible drilling and development costs. Benefits (1) and (3) are expressly provided for by the income tax laws. U.S.C.A., Title 26, Secs. 613(b), 263(c).

Under the depletion allowance, Benefit (1), 27½% of the gross wellhead value of oil and gas produced (up to 50% of the taxable income from the property) is tax free for as long as the property produces, even though the cost of the property is recovered several times over. (Item A: 10:2020.) The legislative history shows that a principal purpose of the depletion allowance was to give an incentive for exploration and development of oil and gas. *United States* v. *Cannelton Sewer Pipe Co.*, 364 U.S. 76, 81; *El Paso Natural Gas Co.* v. *Federal Power Commission*, 281 F.2d 567, 571-72, *certiorari denied*, 366 U.S. 912.

Respecting Benefit (2), even if a well turns out to be dry, it frequently provides much geological and geophysical information for future drilling. Yet the entire drilling cost is deductible from gross income.

As to Benefit (3), the record shows that intangible drilling costs normally comprise about three-fourths of the total cost of drilling and equipping productive wells. (Item III, p. 83; Item A: Ex. 42-J, Sch. 8.) By electing to expense these intangible costs for tax purposes in the year incurred instead of recovering them over a period of years through depletion deductions, the producer receives substantial immediate tax

savings. Furthermore, over the life of a well the effect of expensing intangible drilling costs in conjunction with statutory depletion is to increase the deductions against income in the year the expense is incurred without decreasing deductions in later years. Furthermore, "The most important immediate consequence of electing to expense intangibles is that they may be deducted against the investor's other income." Prentice-Hall, Inc., *Oil & Gas Taxes* (1965), Sec. 2002.5.

This quotation from *Oil & Gas Taxes* leads to the feature which the Examiner emphasizes—spillovers. The evidence establishes that the tax deductions generated by the production activities of the integrated oil and gas companies are so large that not only does the typical independent producer usually pay no tax on his production activities (*Southern Louisiana*, Opinion 546, mimeo., 56), but tax losses resulting from the production activities remain after eliminating all production taxable income. This "excess" of tax losses, or spillovers, is applied to reduce what would normally be taxable income from other business activities, and thereby reduces overall federal income tax liability still further.

Since the independent producer generally does not incur a tax on his domestic production, the Examiner makes no allowance for federal income tax in the gas costings. The result is that the tax deduction benefits from the production of gas which eliminate production taxable income, are passed on to the consumers. But this is not the case with the spillovers. The spillover benefits accrue to the integrated oil and gas companies. The companies utilize the spillovers to reduce taxable income from their many other business activities, and thereby reduce or virtually eliminate their taxes. Hence, the spillovers provide incentives for exploration and development.

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Presiding Examiner's Initial Decision

The record is insufficient to show the exact amounts of production spillover benefits accruing to the respondent integrated producers, but there can be no question that they are large. Rate cases of this Commission involving pipeline companies owning production properties made clear the operation and effect of spillovers in reducing the tax on utility functions other than production, and the magnitude of the resulting tax savings in the pipeline cost of service.

In such a rate case, on the basis of figures supplied by the company from company books and records, and work papers supporting income-tax returns, the Commission computes a tax for the test year to go into the company's cost of service as the allowable tax cost. That type of rate case differs from an

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independent producer area rate case, such as the instant one, in a pertinent respect. There, the consumers receive all tax deduction benefits from the production of gas. The benefits are assigned first to offset or eliminate production taxable income; any balance remaining of those deductions spills over to reduce taxable income arising from the other utility functions, such as transmission and distribution, which, of course, are jurisdictional; and such reduced taxable income is translated into a reduced cost-of-service tax allowance and resulting consumer benefit. Here, as noted, the independent producers are entirely free to apply their spillovers to reduce taxes payable on non-jurisdictional taxable income. See initial decision of Examiner Lande in *Pipeline Production Area Rate Proceeding*, Docket No. RP66-24, mimeo., 91, n. 1. However, the federal income-tax laws operate in exactly the same way in each type of case. Two pipeline cases,

Panhandle Eastern Pipe Line Co., 25 F.P.C. 787, and *Southern Natural Gas Co.*, 29 F.P.C. 323, suffice to illustrate the operation and effect of the spillovers from production.

In the *Panhandle* case, *supra*, where Panhandle's net investment in plant (interstate) was $155,233,256, of which $10,496,211 was well-mouth production properties (p. 863), the Commission computed the tax allowance by employing the statutory deductions relating to depletion and intangible well-drilling costs. The tax on the production properties was zero, and the remainder or spillover available to reduce the taxable income from other functions, $1,388,265. If this tax spillover benefit had not been applied, the federal income tax computed would have been $6,403,520 instead of $4,899,568. (P. 861.) The difference represented a tax saving of $1,503,952 to consumers.

In the *Southern* case, *supra*, at page 358, where Southern's net investment in plant was $231,802,480, of which $9,459,075 was well-mouth production properties, the Commission computed the tax allowance by employing the same special deductions. The result was a tax on the well-mouth production properties of zero; and spillover available to reduce the taxable income from other functions, $1,440,142. Except for this tax spillover benefit, the federal income tax computed would have been $8,234,543 instead of $7,485,669—a tax saving of $748,874 to consumers.

Unquestionably, in like manner huge spillovers generated by production operations reduce the taxable income from the many other functions of the respondent integrated oil and gas companies; and thereby greatly reduce their overall taxes. These functions other than production are listed by the producer group as consisting of "the refining, processing, transportation and

marketing of petroleum products both in the U.S. and abroad; the manufacture of petrochemicals, fertilizers, plastics and other products; the running of restaurants and motels; and a host of other operations too numerous to mention." (Prod. Br., 193.)

The effect of the spillovers on the tax liability of the respondent integrated companies is directly evidenced by Item A: Exhibit 129-J, Stipulation of the Parties Concerning the Evidentiary Introduction of Composited Federal Income Tax Data Drawn from Records on File with the Internal Revenue Service in Lieu of the Actual Federal Income Tax Returns of the "All Areas Questionnaire" Respondents. Exhibit C of Exhibit 129-J was composited from Internal Revenue Service "Transcript-Edit Sheets" which are summaries of actual income-tax return filings for 1962. The companies who filed the returns are 57 of the 69 producer and pipeline-affiliate AAQ companies whose responses were used by the staff in the joint proceeding. Income-tax data for the other 12 companies were unavailable. (Ex. 129-J, p. 27.) Thirty-five of these 57 companies have production in the Other Southwest Area and are parties to the instant proceeding.

The 57 companies are divided in Exhibit C of 129-J into eight "Industry Groups," used by the Internal Revenue Service for statistical purposes. (Ex. 129-J, p. 2.) Of the groups, the most important is Group 291, entitled, "Manufacturing—petroleum refining and related industries—petroleum refining." This group is comprised of 21 companies, of whom 16 are the following respondent major integrated companies: Atlantic Richfield Company, Cities Service Company, Continental Oil Company, Gulf Oil Corporation, Humble Oil & Refining Company,

Kerr-McGee Corporation, Mobil Oil Corporation, Pan American Petroleum Corporation, Shell Oil Company, Sinclair Oil Corporation, Skelly Oil Company, Sohio Petroleum Company, Sun Oil Company, Texaco Inc., Tidewater Oil Company, and Union Oil Company of California.

Exhibit C, Schedule 2, of Exhibit 129-J shows that the gross receipts, or revenues, from all sources, of the 57 independent producers and pipeline affiliates (8 groups) was over $37.5 billion; of which Group 291 (21 companies) had gross receipts of over $31 billion. The schedule further shows that Group 291 had an income tax liability (after investment and foreign tax credit) of only $62 million. When related to gross receipts, the ratio of income tax to gross receipts is .20%, which is 1/5th of 1%. In other words, for every $5 of revenue the federal income tax paid was only 1¢.

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Without spillover of losses from the production department, created by the special tax benefits, the other income producing functions of these integrated companies would have been subjected to regular corporate tax rates. The inference is justified that the *de minimis* amount of tax liability of the companies resulted from utilization of spillover to reduce the taxable income of the other functions.

Only through continued production activities can the producers keep on reaping the spillover benefits. If outlays for exploration and development cease, the spillovers diminish and ultimately cease. Hence, there is automatic incentive for further exploration and drilling with money which would otherwise be paid in taxes.

In addition, the special tax benefits mitigate the investor risk. (Item A: 10:2022, 2026; 87:13,204.) Shaffner pointed out,

"if a firm or an industry does not have to pay taxes, to that extent they only need to earn one dollar in order to have net earnings for dividends of one dollar, whereas if they pay taxes at the regular rate they have to earn approximately two dollars in order to have net earnings of one dollar, and this is an advantage which tends to offset the risk element in the picture.

". . . that is an advantage, it seems to me, in attracting capital whether the industry is regulated or not." (Item A: 87:13,205, 13,207.)

The advantages of the special tax benefits in attracting capital to the industry are even greater now than they were at the time these benefits became law, when lower tax rates prevailed—(percentage depletion, in 1926; expensing of intangibles in 1935). Shaffner testified, "Obviously the appeal to investors of a low-income-taxed industry increases in relative proportion as the alternatives are more heavily taxed." (Item A: 10:2024-25.)

Dr. Alfred E. Kahn, an economist, testified, and the Examiner finds, that "the provisions of our tax laws with respect to the expensing of intangibles and percentage depletion . . . have encouraged a huge flow of capital into this industry." (Item A: Item I-J by Reference, 2.) Such flow of capital has been more than was required. (Item A: 10:2026.)

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Thus, over and over again, the evidence establishes that powerful incentievs operate to spur the independent producers to explore and drill; and the same forces attract capital as well. Hence, the allowed rate of return component of 10½% on flowing gas and new gas-well gas investment is generous.

Why, it may be asked, in view of the special tax deductions, do not the independent producers achieve an average overall return (weighted) on average capitalization higher than 10.3%? The record does not reveal all things about the oil and gas industry. However, it does show that profits have been lower than otherwise because the petroleum industry is overcapitalized. Excessive investment in developmental drilling has resulted in a large amount of idle crude-oil productive capacity. (13:1759; 45:4750; 47:4997; 48:5102; Item III, 29-30; Item A: 10:1993-94, 77:12,149; 78:12,229-30, 12,232; 86:13,131; 87:13,170; Item A: Item I-J by Reference, 2.) For the last year in which there was no overcapacity, 1948, the petroleum industry received a return on equity capital of 20%. (Item III, 32; Item A: Ex. 8-J, Sch. 21.)

Rate of Return Allowance in Previous Area Rate Cases Not Governing.—In *Southern Louisiana* and *Permian*, the Commission allowed a rate of return of 12%, but the 10½% here prescribed is in good part based on reasons and considerations not heretofore brought to the attention of the Commission or ruled upon. Also, in *Permian* part of the allowance was to cover the risk of finding low quality gas. Herein, the Examiner treats the factor of low quality gas as a cost, not risk; and it is not an element in the rate of return. As hereinafter developed, the Examiner reaches ceiling rates for pipeline quality gas by adding on quality improvement costs.

Miscellaneous

Producer Witnesses. The foregoing discussion is a sufficient response to the evidence adduced by the producer witnesses Morton and Dr. Paul H. Cootner, except in one particular as to Cootner. This witness constructed a regression model measuring the depressant effect of the gap between actual and potential Gross National Product on

profit levels. The model indicated that if the integrated petroleum industry had been at full potential in the period 1955-1966, earnings would have been 12.1%.[11]

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(Prod. Br., 188-89.) Cootner expressed the opinion that a rate of economic growth "approaching our economic potential" will continue as a normal condition. (13:1759, 1760-61.) The Examiner rejects this approach as being too speculative and contrary to past experience.

Alternative Investment Opportunities. The producer group hint that unless given the prices they seek for the sale of natural gas, they may divert "available funds . . . to other investment outlets." (Prod. Br., 47, n. 26, 186.) The pipeline group portend this eventuality. (Pipeline Br., 10.) The Examiner would want proof before concluding that the producers have alternative investment opportunities so inviting that they are willing to give up the gas production business with its federal income-tax benefits.

The producer group point out that alternative investment opportunities include exploration for oil, to which pursuit the income-tax advantages apply. However, the only reasonable conclusion to be drawn from the record is that the producers will continue in both the oil production business and the gas production business so as to reap profits and income-tax benefits from both.

State of Texas. The State of Texas contends for an increase in prices, but its arguments fall before the considerations treated of under this heading.

Small Producer. Shaffner frankly testified that he did not know how to determine a rate of return for a small

[11] To the 12.1%, Cootner added four percentage points for the risk of production operations, a position which the Examiner rejects for reasons hereinbefore given.

producer. (Item A: 79:12,327; 86:13,133.) However, certain relevant considerations bearing on this question appear from his testimony and elsewhere in the record.

The risks of the small producer are much greater than those of the large producer; in his drilling operations, the small producer cannot rely on the law of large numbers. (Item A: 10:1996.) On the other hand, there are indications from the record that, in exploration, the small producer is generally looking for oil; and that the natural gas found by him is an incident to such search. (Item III, p. 11; 6:711, 713, 714, 717, 718, 722, 725; Item A: 10:1962, 2246-47.) Moreover, his exploratory efforts are undertaken with the support of the larger companies, through farmouts, acreage and test-well contributions, and other means. (Item A: 10:1962.)

Small producer Richardson argues that small producers should receive "some substantial price advantage." (Richardson Br., p. 3.) ". . . the setting of rates for the smaller producer higher than the area ceilings [is] clearly inappropriate

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as being inconsistent with the area pricing concept." *Southern Louisiana*, Opinion 546, mimeo., 95.

All the rest of the small producers in the instant proceeding who have been heard from do not seek a different or higher price than that received by the majors. (Item A: 10:2260; TIPRO Br.) Apparently, the reason is, as found in *Permian*, the small producers "usually cannot obtain more for their gas than the regulated price we fix for the major producers." 34 F.P.C., at 234, 363. Nor do they seek exemption from regulation. (Item A: 10: 2266.)

TIPRO takes the position that because of the Texas intrastate market its recommended single ceiling price

in the range of 18¢ to 21¢ per Mcf is needed to encourage sales in interstate commerce. (TIPRO Br., 15.) This position involves considerations in addition to rate of return, but is dealt wtih at this point as a matter of convenience.

TIPRO's position is of doubtful validity. The rates herein prescribed for new gas-well gas in Texas Districts 5 and 6 of 17.1¢, and in Texas District 9 of 17.2¢ (exclusive of gathering allowances) would seem to be sufficient to attract gas supplies in Texas to the interstate market. There was testimony at the small producer phase of the hearing that the "top price" for gas in Districts 5, 6, and 9 sold in intrastate commerce is 16¢ plus about ½¢ for half the state taxes. (6:723.) In 1966 the average price for gas sold to pipelines in intrastate commerce in East Texas-Arkansas, and Texas District 9, respectively, was 14.53¢ and 15.91¢. (Ex. 60, Sch. 7, sheet 3.) However, recently a contract was entered into for an intrastate sale in Texas District 6 at 16¢, with escalation of 1¢ every five years until 1982. (6:772-73.) Two small producers testified that they would accept "a somewhat lower price" for intrastate sales than for interstate sales. (6:723, 729-30.)

It is unnecessary for the Examiner to make findings respecting the problem of interstate versus intrastate market for two reasons. First, most of TIPRO's showing was by statement of position, which is not evidence. Second, the question is irrelevant; in ratemaking, the Commission is not authorized to enter into competition with intrastate purchasers. To do so would start vicious circles of price increases to the detriment of the consuming public, interstate and intrastate. However, it may be observed that there is no evidence that the interstate market will be deprived of gas because of intrastate prices.

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IV. COST OF NEW GAS-WELL GAS

Much of the record in this proceeding respecting new gas-well gas cost and flowing gas-well gas cost is the same as that in the *Hugoton-Anadarko* and *Texas Gulf Coast* joint proceeding, except for supplementary evidence. For this reason the initial decisions of Examiner Kane in *Hugoton-Anadarko* and Examiner Taylor in *Texas Gulf Coast* have particular applicability. From consideration of all of the evidence (consisting of that incorporated by reference and that adduced for the first time at the hearing herein) and the briefs, the Examiner agrees with such decisions on many of the questions presented both in the joint proceeding and the instant proceeding. Accordingly he incorporates by reference as part of this decision, numerous applicable portions of the Kane decision. The treatment in the Kane and Taylor decisions of questions respecting gas costs is generally the same or similar; but in the interest of simplicity, only excerpts from the Kane decision will be incorporated here. In all instances where portions of that decision are incorporated by reference, they express the independent judgment of this Examiner; and he adopts them as his own.

Successful Well Costs

Upon the question of the per-foot cost of successful gas wells, the Examiner incorporates by reference as a part of this decision, the following portions of the initial decision in *Hugoton-Anadarko*: (1) the paragraph commencing at the bottom of mimeo. page 40, and concluding at the top of mimeo. page 41; (2) the first full paragraph on mimeo. page 41; and (3) the first paragraph on mimeo. page 42.

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Presiding Examiner's Initial Decision

In his testimony given in the instant proceeding, producer witness Dr. Stephen F. Sherwin relies primarily on a drilling cost study presented by producer witness Celia Star Gody. From this study, he determines an average cost per foot of $18.41 for the period 1961-1965. Sherwin also shows an alternative calculation, which he refers to as Opinion 468 procedure. In this calculation, he trends forward the per-foot cost shown in U.S. Bureau of the Census, *1963 Census of Mineral Industries*, to a 1965 figure of $17.93, using the results of the Gody study.

The Examiner is of the opinion that the *1963 Census* per-foot cost is a more reliable figure than that obtained from the Gody study. Respecting Sherwin's alternative calculation, in the Examiner's opinion, the *1963 Census* drilling costs are not understated, and this witness' trending forward to the 1965 figure is unjustified.

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The producer group contend that the *Census* cost for a single year, 1963, is not representative. (Prod. Br., 91.) "The basic fallacy with the producers' contention," Examiner Kane correctly stated, "lies with their comparison of 1963 figures for depth, location, and type with those of a few years, instead of with the corresponding figures for the entire span of 8 years shown in [Item A-] Exh. 38-J, Sch. 18-20, updated to include 1965 figures. The more meaningful comparison of such schedules for the entire updated period 1958-1965 would support the conclusion that the 1963 drilling figures in fact approximate the average for such 8-year period whether measured by depth, location, or type." (*Hugoton-Anadarko*, mimeo., 41.)

Next to be considered is the productivity of drilling, the denominator of the successful well costs. Productivity of drilling is computed herein in a manner similar to that utilized in *Permian*, by relating the reserve additions of nonassociated gas to gas-well footage drilled. The reserve additions of nonassociated gas must be estimated for the years prior to 1966, since up to that time the AGA Reserves Committee reported only total gas reserve additions. In the joint record, the estimates of such reserve additions were presented by AGD witness Dr. Jules Joskow, following *Permian* methods; and were utilized by all witnesses testifying on current costs. Starting with 1966, the AGA Reserves Committee reported reserve additions of nonassociated gas. In this proceeding, Sherwin used the actual figures thus obtained for 1966, as does this Examiner for 1967.

All witnesses calculating productivity, both in the joint proceeding and this proceeding, use American Gas Association reserves and *World Oil* footage data. The current staff exhibit employs unrevised *World Oil* data, whereas the current Sherwin exhibit reflects revised *World Oil* figures, which are preferable. Except for dissimilarity in source material in this respect, the differences in productivity per foot drilled arrived at by the various witnesses are occasioned by selection of different periods for averaging productivity.

In the instant proceeding, Sherwin uses the seven-year period 1960-1966, arriving at an average of 581 Mcf. In his alternative calculation, he looked to the period 1947-1966, determining average productivity at 594 Mcf. Staff witness William T. Loring relied on the period 1957-1966, resulting in an average productivity of 608 Mcf. The joint-record studies of Carl S. Quinn, a witness on behalf of Panhandle, and Herman G. Roseman, a witness on behalf of AGD, reflect average productivity figures of

582 Mcf and 586 Mcf, based on use of the 1947-1962 and 1947-1964 periods, respectively.

For 1966 and 1967, productivity has been considerably

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higher than the average for the previous years; but this fact is insufficient to indicate a distinct trend in the annual additions of nonassociated gas reserves per gas-well foot drilled. The Examiner is of the opinion, as was Examiner Kane, that a more accurate future projection can be obtained by making use of the complete span of years for which data are available. (*Hugoton-Anadarko*, mimeo., 43.) Consequently this Examiner employs the period 1947-1967.

The basic data which the Examiner uses in the calculation are from the Sherwin Exhibit 3-A, Sch. 4, sheet 2, since it employs revised *World Oil* figures. See *Southern Louisiana*, Opinion 546, mimeo., 35. The 1967 data are obtained by reference to AGA and *World Oil* publications.[12] The productivity for the 1947-1967 period thus arrived at is 612 Mcf per foot. Dividing the 1963 final *Census* cost per foot of $16.48 by the 612 Mcf yields a unit cost of 2.69¢ per Mcf. The Examiner adopts this figure as the unit cost of successful gas wells.

Lease Acquisition Costs

The Examiner incorporates by reference, as part of this decision, the first two paragraphs on mimeo. page 44 of the initial decision in *Hugoton-Anadarko*.

All estimates of total lease acquisition expenditures are based on Chase Manhattan Bank annual lease acquisition costs but differ as to the period of years to be util-

[12] *AGA Reserves Report, 1967; World Oil*, February 15, 1968.

ized. The *Hugoton-Anadarko* initial decision employed the period 1955-1965. This period commenced with the earliest year for which figures were used by any of the witnesses and continued through the last year for which figures were available. In the instant proceeding, the staff look to the Chase data for the period 1957-1965.

The producer group contend that the period should be confined to the 1960's because of a "rapid rise in leasehold acquisition expenditures" attendant upon large federal offshore lease sales. They recommend basing the estimate of leasehold acquisition expenditures on the annual average experienced over the 1961-1966 period, approximately $590 million. (Prod. Br., 95.) The Examiner agrees with, and accepts, the producer group's recommendation.

Examiner Kane's sound treatment of the proper allocation of leasehold acquisitions, a highly complex topic, is incorporated

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by reference. This treatment commences at the top of mimeo. page 45 of the *Hugoton-Anadarko* initial decision and continues to and including the first paragraph on mimeo. page 49.

The total lease acquisition expenditures reported by Chase Manhattan over the 1961-1966 period were $3,535,000,000. Allocation of such costs on the basis of an overall ratio between lease expenditures and total successful well costs for the same period would, in effect, allocate 30.9% of the costs to gas.[13]

[13] Reported *World Oil* footage for gas of 158,939,000 feet, multiplied by $15.76 per foot (1963 final *Census* figure excluding costs beyond the Christmas tree) = $2,504,879,000. Reported *World Oil* footage for oil, 477,082,000 feet, multiplied by $11.74 per foot (1963 final *Census* figures excluding costs beyond the Christmas tree) = $5,600,943,000. The total drilling cost is $8,105,822,000, of which 30.9% is gas and 69.1% is oil.

Adjustment of the overall ratio of lease expenditures to well expenditures of 43.6%, based on industry-wide data excluding costs beyond the Christmas tree,[14] to reflect the 1.27 ratio of the ratios based on investment, results in the allocation of 36.2% of lease expenditures to gas rather than the 30.9 previously indicated.[15] The adjusted overall ratio then becomes 51.1% instead of 43.6%.[16] Applying this adjusted ratio to the 2.57¢ per Mcf of successful well costs (reflecting exclusion of costs beyond the Christmas tree from the *Census* drilling cost figures), it is found that the allowance for lease acquisition costs amounts to 1.31¢ per Mcf.

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Other Production Facilities

The allowance herein for cost of other production facilities includes (a) costs for lease equipment, (b) related producing facilities, and (c) apportioned overhead investment. (34 F.P.C., at 198.) The Examiner incorporates by reference the portion of the initial decision in *Hugoton-Anadarko* commencing with the second paragraph on mimeo. page 51 and continuing through the first complete paragraph on mimeo. page 52. *Southern Louisiana*, Opinion 546, mimeo. pages 36-37, is a precedent in addition to *Permian* for the basic method here used of calculating a cost for other production facilities.

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[14] Lease acquisition expenditures of $3,535,000,000 divided by total drilling costs of $8,105,822,000.

[15] $$\frac{(30.9)\quad(1.27)}{(30.9)\quad(1.27)\ +\ 69.1} = 36.2\%$$

[16] $$43.6 \times \frac{36.2}{30.9} = 51.1\%$$

The total allowance of 2.69¢ per Mcf hereinabove provided for successful gas wells includes 0.12¢ per Mcf for part of the lease equipment costs beyond the Christmas tree.[17] Accordingly, this sum must be deducted from the total amount calculated for the cost of other production facilities in order to avoid a partial double allowance.

Relying on AAQ data on gross plant relationships for gas leases, AGD witness Roseman calculates that lease equipment costs constitute 7.53%; and off-lease production investment 9.80% of successful well costs. Application of the total of 17.33% to the successful well cost of 2.57¢ per Mcf (costs through the Christmas tree) as determined, *supra*, results in a gross allowance of 0.45¢ per Mcf. Deducting the 0.12¢ per Mcf, the resulting 0.33¢ per Mcf is the amount found to be the net allowance for cost of other production facilities.

Producer witness Sherwin estimates an allowance of 0.57¢ per Mcf for other production facilities. He first determines an average annual industry-wide expenditure for this item of $500 million, by reference to JAS data for the period 1960-1964. He allocates 18% of this amount to gas reservoirs, using the same allocation method as he used in AR64-1 and AR64-2; but makes a

new adjustment to overcome criticism to the effect that he had understated the relative cost of lease equipment

[17] The 2.69¢ per Mcf was arrived at by using, among other things, the cost of drilling and equipping wells of $16.48 per foot for gas wells as shown by *1963 Census of Mineral Industries* in Table 6E. Reference to the same table shows that the cost of gas-well footage, excluding costs beyond the Christmas tree, is $15.76. In addition, Table 6E shows that the cost of the lease equipment beyond the Christmas tree which is included in the Census Bureau data is 4.42% of gas-well cost and lease equipment ($ 18,380,000). 4.42% of 2.69¢ = $.12¢. ($416,062,000)

and related facilities on oil leases as compared to gas leases.

Examiner Kane's observations in *Hugoton-Anadarko*, mimeo. page 53, speaking of Sherwin's method there used, apply here as well: ". . . based as it is upon JAS expenditure data for lease equipment and related facilities, although purportedly corroborated by another source, [it] does not furnish a sufficiently reliable foundation for departure from the Commission-established precedent.

"While JAS estimates may be reliable for some purposes, such as total wells and total footage, there is nothing in this record to demonstrate that the expenditure estimates for lease equipment and related facilities are any more reliable than the JAS cost estimates found unreliable by the Commission for the reasons stated in Opinion 468." Likewise, the Commission's statement in *Southern Louisiana*, mimeo. page 37, respecting producers' calculations of a cost for other production facilities is applicable here: ". . . the producers' preferred calculations start with JAS figures that are unexplained and uncorroborated."

Dry-Hole Costs

Pages 55 and 56, except the paragraph at the bottom of page 56, of the initial decision in *Hugoton-Anadarko* are incorporated by reference.

Sherwin found an allocated unit cost of 2.01¢ per Mcf. He relies, *inter alia*, on a dry-hole cost per foot of $11.27 developed by him from Mrs. Gody's study; and employs the new allocation method presented by him in *Hugoton-Anadarko* and *Texas Gulf Coast*. (9:1013.)[18] Using the final 1963 *Census* dry-hole cost of $8.69 per foot, Loring

[18] Sherwin also shows a cost of 1.55¢ per Mcf "under the Opinion 468 technique." (9:1016-17.)

and Roseman determined respective allowances of 1.63¢ per Mcf and 1.43¢ per Mcf. Roseman follows the *Permian* method of allocation; Loring modifies that method to reflect the tracing of developmental dry holes, a modification rejected herein.

Contrary to Sherwin's contention, his method does not provide a modification of the *Permian* method "in the direction of ascertaining a closer approximation of in-fact costs . . . ." (Item A: 71:10,402.) He fails to reflect the overall downward adjustment in dry-hole footage allocable to gas resulting from the generally higher success ratio which accompanies deeper

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drilling for gas. The adjustment was found to be proper in *Permian*, and is confirmed on the basis of the instant record. Failure to recognize this adjustment is particularly inapt where, as here, the witness does adjust for the higher cost of such deeper driling. Further, Sherwin, in determining the cost differential between so-called "gas" dry holes and "oil" dry holes, relies on AAQ data reflecting respondents' expression of intent. These data have not been shown to be representative of the industry. Further, Sherwin's result of 2.01¢ per Mcf reflects a dry-hole cost per foot based upon Mrs. Gody's drilling cost study instead of the 1963 *Census* data, which have been previously found to provide "a sound basis for deriving current cost estimates in this proceeding." Finally, his result reflects a level of reserves which he says is implied by his productivity figure of 581 Mcf added per gas-well foot drilled, whereas the Examiner has determined the appropriate productivity to be 612 Mcf per foot. The Examiner, however, follows that part of Sherwin's method which relates to the cost differences between exploratory and developmental drilling.

To implement the adoption of *Permian* methodology in connection with dry hole costs, the Examiner has utilized relevant parts of Loring's and Roseman's evidence, modified to reflect separate imputed costs per foot for exploratory and developmental dry holes as advocated by Sherwin. This technique results essentially in a more refined division of dry-hole costs, on the basis of the relationship between successful oil and gas-well footage averaged over a period of years. It also provides the proper solution in resolving the issues involved, as well as the differences arising out of the witnesses' treatment thereof. Application of this technique results in a dry-hole allowance in the new-gas costing calculations of 1.41¢ per Mcf. This result gives effect to the Commission-endorsed adjustments designed to reflect the proposition that the deeper drilling for gas tends to bring in its wake a higher success ratio but results also in a higher cost per foot.

For the period 1951-1967, revised *World Oil* footage figures presented by Roseman indicate that an allocation of dry-hole footage on the basis of successful footage (separately for exploratory and developmental drilling), disregarding depth, results in an overall ratio of 0.897 allocated dry-hole foot per successful gas-well foot. (Item A: Ex. 66-J, Sch. 7, updated through 1967.)

The overall dry-hole footage so allocated to gas breaks down to approximately 60.7% exploratory and 39.3% developmental. (Item A: Ex. 42-J, Sch. 10, sheet 2; and Sch. 11, sheet 2, both

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updated through 1967.)[19] Application of this percentage

[19] Roseman's allocation, though also recognizing this separation between exploratory and development drilling, is not in sufficient detail to permit calculation of the percentage breakdown implicit in his overall result. (See Item A: Ex. 66-J, Sch. 7, and underlying Ex. 13-J, Sch. 6.)

breakdown to the 0.897 footage factor results in an exploratory ratio of 0.544 and a developmental ratio of 0.353.

The next step in the calculation is designed to give effect to the higher success ratio at greater depths in gas-well drilling. On the basis of data presented by Loring (Ex. 20, Sch. 8), the staff calculate the effect as resulting in a reduction of 9% of the exploratory dry-hole footage allocated to gas and an increase of 1.5% in the developmental.[20] Thus, taking this depth factor into consideration, the result is a reduction of the exploratory ratio from 0.544 to 0.495, an increase of the developmental ratio from 0.353 to 0.358, and an overall adjusted dry-hole ratio of 0.853 dry-hole foot per successful gas-well foot.

The next step in the process is designed to give effect to the higher cost per foot of deeper drilling for gas. In order to obtain the implied separate cost per foot for exploratory dry holes and developmental dry holes, it is necessary to develop the relationship between their respective footages as well as their respective per-foot dry-hole costs. As to the former, the unallocated exploratory dry-hole footage constitutes approximately 48.7% of the total dry-hole footage. (Item A: Ex. 42-J, Sch. 10, sheet 2, updated through 1967.)

Respecting cost per foot, Sherwin, in reliance on AAQ Schedule F-2 data, concludes that exploratory dry-hole costs per foot are approximately 35% greater than those for developmental dry holes. (Item A: Ex. 42-J, Sch. 10, sheet 1.) The 1963 revised *Census* figure for overall dry-hole costs of $8.69 per foot, after applying Serwin's 35% higher cost for exploratory dry holes and the footage breakdown shown above, results in separate imputed costs

[20] Roseman shows these figures to be 9.1% and 1%, respectively. (Item A: Ex. 66A-J, Sch. 10, Revised.)

per foot for exploratory and developmental dry holes of $10.03 and $7.43, respectively.[21]

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These costs must be further adjusted to reflect the higher cost of deeper drilling for gas. The staff calculate that exploratory dry-hole footage allocated to gas by depth range costs 12.9% more per foot than the average exploratory foot; coincidentally, the higher cost for developmental dry-hole footage so allocated is also 12.9%. (Ex. 20, Sch. 14, sheet 2.) Application of these percentages results in adjusted costs of $11.32 and $8.39 per foot.

Weighting these costs by the respective allocated footage ratios of 0.495 and 0.358 applicable thereto and adding the products together, there is found a weighted average dry-hole cost per gas-well foot. This cost, when divided by the productivity figure of 612 Mcf, results in a figure of 1.41¢ per Mcf, the allowance for dry-hole cost made herein.

Other Exploratory Costs

Geological and Geophysical Expenses and Lease Rentals. In computing the allowance for this item in the new-gas costing, the Examiner follows the Commission's basic methodology in *Permain* (34 F.P.C., at 193) and *Southern Louisiana* (mimeo., 28). Application of such methodology results in a unit allowance of 1.36¢ per Mcf.[22]

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[21] (0.487) (1.35x) + (0.513) (x) = $8.69.
Cost per foot, developmental dry holes = $7.43.
Cost per foot, exploratory dry holes = $10.03.

[22] Quinn, Roseman, and Loring used the *Permian* approach in arriving at their respective allowances for this item of 1.09¢, 1.09¢, and 1.14¢ per Mcf. (Item F: Ex. 82-1; Item A: Ex. 66-J; and Ex. 20.)

The ratio of geological and geophysical expenses (G&G) and lease rentals to the expenditures for lease acquisitions, as shown by Chase Manhattan Bank data for the period 1961-1966, is 104%.[23] The unit allowance of 1.36¢ is arrived at by applying this ratio to the 1.31¢ per Mcf unit allowance made herein for lease acquisitions.

Producer witness Sherwin is the only witness departing from *Permian* techniques in determining the allowance for G & G and lease rentals. He finds an average annual expenditure level of $615 million for G&G, land department expenses, and lease rentals, by reference to Chase Manhattan data "for the last six to seven years." He allocates this amount between gas reservoirs and oil reservoirs on the basis of successful well costs, and calculates

an allowance of 1.16¢ per Mcf.[24] (9:1017-18.) The Examiners in the joint proceeding rejected this method because "no reason appears for departing from the Commission's adopted methodology." (Hugoton-Anadarko, mimeo., 62.) This Examiner rejects the Sherwin method on the same ground.

Exploration and Development Overheads. In *Permian*, this item was determined by reference to the relationship between "exploration and development overheads" and total finding and development costs as shown by JAS, the only available source for such overheads. The ratio so developed was then applied to the sum of the finding and development costs found by the Commission (*i.e.*, suc-

[23] Ex. 3-A, Sch. 9, sheet 1. This is the same period adopted herein for determining the allowance for lease acquisitions.

[24] Sherwin shows a combined allowance of 1.56¢ per Mcf for "other exploratory costs." The separately computed amounts are 1.16¢ for G&G and lease rentals, and 0.40¢ for overheads.

cessful wells, lease acquisitions, other production facilities, dry holes, and G&G and lease rentals) to yield an overhead allowance. (34 F.P.C., at 193.) The Commission followed the same method in *Southern Louisiana*. (Mimeo., 28.)

In the instant proceeding, the staff witness Loring uses a modified method to avoid a duplication or "double count" of overheads. He testified that "exploratory and developmental overheads relating to successful well and lease expenditures are already included in my computation as a part of Other Production Facilities. Thus, the only other overheads are related to dry holes and to the other exploratory costs not connected directly with successful wells or leases." (9:1248.) Consequently, in stead of obtaining a relationship between total exploration and development overhead and total finding costs, Loring develops a similar relationship between exploration overhead and exploration expenditures. This relationship, reflecting the average for the period 1959-1963 as shown by JAS, is 13.9%.[25] Loring applies the relationship to the sum of his allowances for dry holes, and G&G and lease rentals, thereby obtaining an overhead allowance of 0.39¢ per Mcf. (9:1248-49; Ex. 20, Sch. 1 sheet 2.)

Sherwin shows JAS exploration overhead data for the years 1959-1964. (Ex. 3-A, Sch. 9, sheet 1.) He adopts an average annual overhead level of $210 million. As in the case of G&G and lease rentals, he allocates this dollar amount between gas reservoirs and oil reservoirs on the basis of the cost of successful wells. The resulting allowance for overheads is 0.40¢ per Mcf. (9:1018.)

[25] Inclusion of more recent JAS data gives the same result.

Although there is not much difference in the results reached by Loring and Sherwin, the Examiner prefers Loring's procedure. Sherwin's procedure departs substantially from *Permian* methods, where as Loring follows *Permian* and merely imposes a refinement to eliminate a double count. Applying Loring's percentage to the sum of the allowances for dry holes, and G&G and lease rentals, found herein (2.77¢ per Mcf), the Examiner finds an overhead allowance of 0.39¢ per Mcf.

Adjustment for Exploration in Excess of Production

The Examiner follows *Southern Louisiana*, Opinion 546, mimeo. pages 28-30, the most recent precedent. There, the Commission determined a gas-well gas findings-to-production ratio for the period 1961-1966. In reaching this determination, the Commission multiplied 587 Mcf per foot (the adopted productivity figure) by *World Oil* gas-well footage drilled in that period; and divided the total findings figure thus computed by AGA gas-well gas production for that period. The result was an average F/P ratio for the six years of 1.378. Exercising "careful judgment rather than scientific formula," the Commission concluded that the total allowance for exploration and development should be 1.37 times the cost before adjustment; in other words, that the adjustment should be 37%.

The following table is patterned on the table in *Southern Louisiana*, mimeo. page 29, which the Commission used in reaching its decision to allow a 37% adjustment factor (volumes are at 14.65 psia):

Year	*World Oil* Gas Well Drilling Footage[a]	MMMcf of Finding: Footage x 612	MMMcf of AGA Gas-Well Gas Production[b]
1961	29,292	17,927	9,740
1962	28,950	17,717	10,005
1963	24,533	15,014	10,866
1964	25,597	15,665	11,533
1965	24,931	15,258	12,223
1966	25,636	15,689	13,178
1967	21,482	13,147	13,713
		110,417	81,258

[a] Ex. 3-A, Sch. 4, sheet 2 for years 1961 through 1966. See *World Oil*, February 15, 1968, issue, for 1967 figure.

[b] Ex. 66-J, Sch. 18, for years 1961 through 1964. Data for 1965 through 1967 are taken from the *AGA Reserves Report, 1967*, pp. 225, 126.

The significant differences between this table and that shown in *Southern Louisiana* are: (1) addition of 1967 data; (2) use of a productivity figure of 612 Mcf per foot (instead of 587); and (3) use of actual AGA-reported gas-well gas production for 1965 and later years instead of estimates based on AGA-reported total gas production.

The findings-to-production ratio for gas-well gas thereby obtained is 1.359 $\left(\frac{110,417}{81,258} = 1.359\right)$, as compared with the 1.378 found in *Southern Louisiana*. Both the ratio derived in *Southern Louisiana* and that derived here, "point to an adjustment figure in the range of 35 to 40 percent." In the Examiner's opinion, a figure in this range is a "desirable expenditure in the public interest."

Permian, 34 F.P.C., at 194. In these circumstances, the Examiner sees no reason for departing from the 37% used by the Commission in *Southern Louisiana*.

Applying the 37%adjustment figure to the sum of the allowances herein for dry holes, G&G and lease rentals, and exploration overhead, gives 1.17¢ per Mcf as the allowance for exploration in excess of production.

Sherwin generally would use the method employed in *Permian*. He computes an adjustment factor of 41%. This factor is derived from a comparison of an average of 15.5 trillion cubic feet of reserve additions for the period 1960-1966 said to underlie the witness' cost components, and average annual gas-well gas production of 11.0 trillion cubic feet over the same period. Use of the 41%factor with Sherwin's unit exploration and development cost (E&D) would result in an allowance of 1.46¢ per Mcf. (Ex. 3-A, Sch. 1) In their initial brief, the producers say that the same adjustment factor of 41% is derived by the *Southern Louisiana* method, using net production and gas-well footage drilled in the period 1960-1966 and productivity for that same period. (P. 108, n. 72.)

Sherwin abandons the *Permian* technique in using a six-year period instead of a four-year period; in so doing, he includes data for the atypical year 1962. The producers' brief abandons the *Southern Louisiana* technique in commencing with 1960 instead of 1961 data for footage drilled and net production; and further, in computing productivity commencing with 1960 data rather than 1947 data.

In the Examiner's view, the producers and their witness have failed to justify departure from the 37% adjustment allowed in *Permian* and *Southern Louisiana*.

Production Operating Expenses

The Examiner incorporates by reference the entire treatment of Production Operating Expenses in the initial decision in *Hugoton-Anadarko*, mimeo. pages 68 to 70, inclusive; except that the following words and figures are substituted for footnote 3 at the bottom of page 69: "3 Ex. 20, Sch. 13, sheet 1."

Net Liquid Credit

Upon the authority of *Permian*, 34 F.P.C., at 195-96, and *Southern Louisiana*, Opinion 546, mimeo., 31-32, the Examiner includes a credit allowance for liquids derived from gas-well gas. In arriving at the amount of this credit allowance, the initial question to be determined is whether the computation should reflect reserve additions or actual production experience.

AGD argues that the figure for net liquid credit should measure the revenue yield of new gas-well gas reserve addition rather than the revenue yield of all gas production; hence, that the reserves-added approach is preferable. (AGD Br., 14.) The producers urge use of the production basis. They correctly say that "reserves additions for natural gas liquids (NGL) are not separately reported for condensate and plant liquids, nor was it possible, prior to 1965, on the basis of published data, to ascertain the NGL reserves additions separately for nonassociated as distinguished from associated gas." (Prod. Br., 111.)

Conceptually, it would be desirable to compute the liquid credit by reference to reserve additions, as AGD argues. However, the Examiner is persuaded by other considerations of greater weight that the liquid credit should be measured by production volumes. There are the

technical difficulties in employing the reserves additions basis pointed out by the producer group. In addition, the Examiner agrees with Examined Kane in the initial decision in *Hugoton-Anadarko* that, "The production basis provides a better measure of the current and expected experience in the foreseeable future." (Mimeo., 71.)

The staff witness recommended a net liquid credit of 3.69¢, but the staff in their brief say that this figure "may well be at the lower end" of a range of reasonableness. (Staff Br., 127.) Producer witness Sherwin calculated a total net liquid credit of 3.72¢ Mcf. (9:1022.) In rebuttal to Sherwin, Dr. Bruce C. Netschert, a witness on behalf of AGD, presented evidence to support a net liquid credit of not less than 3.67¢ per Mcf. (13:1823.) In their brief, AGD contend for an allowance of 3.84¢ per Mcf, based on Roseman's testimony in the joint record. (AGD Br., 14.)

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The Examiner adopts the producers' analysis of liquid credit into three component parts: lease condensates, plant condensates, and other plant liquids (extracted liquids).

Lease Condensates. The producer group assert that The Oil and Gas Journal is the most reliable source for lease-condensate production volumes data, and that such data show no upward trend in recent years in barrels per MMcf. (Examiner Kane so found in *Hugoton-Anadarko*, mimeo., 73.) This Examiner agrees.

From *The Oil and Gas Journal* data, Sherwin shows a lease-condensate-to-gas ratio of 9.6—9.7 barrels per MMcf for 1965-1966. Using a ratio of 9.7 and a value of $3.00 per barrel shown by Shewin, the producer group calculate a maximum gross lease credit (before production tax and royalty) of 2.92¢ per Mcf. (Prod. Br., 113.)

Exhibit 19, prepared by staff witness Louis J. Engel, shows *The Oil and Gas Journal* lease condensate production and AGA gas-well gas production for the period 1961-1966. The exhibit also shows another reliable measure of lease condensate production, obtained by subtracting U. S. Bureau of Mines total plant liquids from total AGA natural-gas liquids. The results, in barrels per MMcf, are as follows:

Year	O & G J	AGA less BOM
1961	9.53	10.26
1962	10.16	9.73
1963	9.67	10.56
1964	10.05	9.85
1965	9.65	10.08
1966	9.73[a]	9.88[b]
1961-1966	9.8	10.1
1962-1966	9.9	10.0

[a]Based on revised data at 30:3578-79.

[b]Based on *AGA Reserves Report, 1967*, 225.

Upon the basis of these two groups of ratios for the period 1961-1966, the Examiner finds, as did Examiner Kane based on data for 1962-1965 *Hugoton-Anadarko* initial decision, mimeo., 74), that 10 barrels of lease condensate per MMcf. is a valid ratio.

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The Examiner finds that the value of lease condensate, determined from the AAQ, is $3.02 per barrel. (9:1230.) The gross credit for lease condensates is, therefore, 3.02¢ per Mcf. The royalty interest hereinafter allowed is 14%. (*Infra*, p. 71.) With this royalty interest and a

5.6% condensate production tax (9:1230-31), the net credit comes to 2.45¢ per Mcf. The Examiner finds and concludes that this figure is a reasonable allowance for lease condensates.

Plant Condensates. Sherwin shows, from Bureau of Mines data, that the yield of plant condensates (including finished gasoline, naptha, and "other products") has been about 3.5 to 3.6 barrels per MMcf—1963, 3.6; 1964, 3.5; 1965, 3.5; 1966, 3.6. (Ex. 3-A, Sch. 10.) From the same source, the value averages $3.09 per barrel—1963, $3.06; 1964, $2.99; 1965, $3.07; 1966, $3.25. The Examiner finds, therefore, that the gross credit for plant condensate is 1.08¢ per Mcf., and the net credit (after 5.6% production tax and 14% royalty), 0.88¢ per Mcf.

Other Plant Liquids. Plant liquids, or extracted liquids, include ethane, LP gases (essentially propane and butane), and natural gasoline. The determination of the credit for this item requires findings on several subsidiary issues.

The producer group correctly say, based on evidence in the joint record, "Any estimate of plant liquid credit is dependent on the liquid yield of gas-well gas production, the price of liquids, the proportion of revenues credited back to the lease, the percentage of fuel loss and the degree to which producers reserve participation in processing." And further, "No new light has been shed on these factors and concepts in this record; in essence, the parties have applied the same techniques of analysis to more recently available data." (Prod. Br., 114.)

In reaching the net credit for extracted liquids, the Examiner generally applies the methodology of producer witness B. R. Carney, with certain modifications. The first item in the calculation is the price received for the liquids extracted at the plants. The Examiner's determination of this price is based on Bureau of Mines data

for five southwestern States—Texas, Oklahoma, Kansas, Louisiana, and New Mexico. As shown by these data, the unit revenue per gallon was 4.26¢ in 1963; 4.18¢ in 1964; 4.49¢ in 1965; and 4.92¢ in 1966.[26] The average for the

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four-year period 1963-1966 is 4.46¢ per gallon; and the average for the three-year period 1964-1966, 4.53¢ per gallon. Upon the basis of this evidence, the Examiner finds and concludes that 4.50¢ per gallon is a reasonable and proper price to use in the calculation as the unit revenue for the liquids extracted at the plants.

The Examiner incorporates by reference the paragraph from the initial decision in *Hugoton-Anadarko* commencing at the bottom of mimeo., page 75 and continuing to the bottom of mimeo. page 76.

As to the percentage of plant liquid revenue credited to the lease, Carney testified that he knew of no precise method for deriving a value for the payback percentage short of a detailed analysis of thousands of gas sales and gas processing contracts. He adopted a 40% value for this factor, based primarily on his experience and knowledge of the industry. (Item A: 76:11,444.) The Examiner accepts and adopts the 40% figure, in reliance upon Carney's expertise.

Next, there is incorporated by reference the second paragraph on mimeo. page 77 of the initial decision in *Hugoton-Anadarko.*

As to the proportion of gas-well gas produced which is processed, all witnesses testifying on the point agree

[26] 1966 figure, calculation from U.S. Bureau of Mines, *Minerals Yearbook 1966* (published late in 1967), 787. The figures for the other years, as correctly calculated from earlier *Yearbooks*, are set out in the initial decision in *Hugoton-Anadarko*, mimeo., 75.

that assumptions are necessary. Sherwin recognizes that there has been a rise in the percentage in recent years and takes that fact into account in reaching his credit recommendation. (9:1022.) Engel estimates that 67% of all gas-well gas production is processed for liquid removal. His estimate is derived from Bureau of Mines data; and reflects elimination of volumes which are processed twice, "that is, once in field plants and once again in remote plants on pipelines." The estimate also reflects an underlying estimate that 90% of oil-well gas production is processed. (9:1236-7; Ex. 19, Sch. 2, sheet 6.) Engel shows percentages of 67.2% gas-well gas processed in 1964 and 68.6% in 1965. Applied to more recent data taken from Bureau of Mines, *Minerals Yearbook 1967*, his procedure yields a figure of 70.4% for 1966 and 69.5% for 1967. The Examiner concludes that an allowance of 69% is reasonable and justified.

A producer participation factor is to be added to the calculation of net liquid credit because substantial volumes of gas-well gas are sold outright from leases without any reservation of liquid payment, and subsequently processed. In the joint record, Carney concluded that the producer participation factor is 60%, but his supporting facts are nebulous. In the

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instant proceeding, Engel testified, "Since producers commonly build plants to primarily serve their own gas leases an secondly to buy or custom process other gas it can be assumed that producers will share in the liquid revenue generated from at least 84% of total plant liquids produced." (9:1235.) The Examiner adopts a factor of 85%.

Application of the figures and percentages arrived at herein results in a gross extracted liquid credit of

0.69¢ per Mcf. Credit must be given the producer for payment of the royalty interest of 14%, and for payment of production taxes estimated by Engel to be 4%. Application of the total royalty and production tax to the 0.69¢ gross plant liquid credit results in a net extracted liquid credit of 0.57¢ per Mcf.

The net liquid credit tabulation is set out in the following tabulation:

Liquid yield of gas-well gas	0.84 GMP
Unit revenue	4.5¢/gal
Liquid revenue per Mcf processed	3.78¢
Proportion of revenue credit back to lease	40%
Liquid revenue per Mcf processed credited back to lease	1.51¢
Fuel loss	0.34
Liquid revenue per Mcf processed credited back to lease, net of fuel loss	1.17
Proportion of gas-well gas produced which is processed	69%
Liquid credit per Mcf produced	0.81¢
Producers' participation factor	85%
Liquid revenue per Mcf produced attributable to producer	0.69¢
Net credit after 4% production tax and 14% royalty	0.57

Summary. It has been seen that the net liquid credit allowed under the foregoing subheads is 2.45¢ for lease condensate, 0.88¢ for plant condensate, and 0.57¢ for other plant liquids; or a total of 3.90¢ per Mcf.

The *AGA Reserves Report, 1966* presented for the first time data including the annual production and reserve additions for nonassociated natural-gas liquids. The years covered were 1965 and 1966. These and subse-

quent data support the reasonableness of the net liquid credit allowance of 3.90¢ per Mcf. Inherent in the 3.90¢ per Mcf is a total yield of 27.3 barrels of nonassociated gas liquids per MMcf of nonassociated gas production:

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Lease condensate	10.0	barrels/MMcf
Plant condensate	3.5	" "
Other plant liquids	13.8	" " *
	27.3	

* Calculated from the subsidiary findings made herein.

Calculations from the 1967 *AGA Reserves Report* show the following ratios of total nonassociated natural-gas liquids per MMcf of nonassociated natural-gas production (at 14.65 psia):

1965	28.7	barrels/MMcf
1966	27.4	" "
1967 (preliminary)	28.7	" "

Thus, from the newly available AGA data, the 1965-1966 average is 28.1 barrels per MMcf; and the 1965-1967 average, 28.3 barrels per MMcf.

The 27.3 barrels per MMcf inherent in the 3.90¢ credit calculation is slightly less than these averages. But the AGA data include liquids which are removed at remote pipeline plants and are therefore unavailable as a producer revenue source.

Regulatory Expense. No evidence was offered on regulatory expense in addition to that adduced in the joint record. There, a staff witness and an AGD witness each came up with a recommended allowance of 0.14¢ per Mcf. (Item A: 71:10,584; 10,776-77.) The figure derived by a producer witness, adjusted to reflect a 10½%

rate of return, is 0.15¢ per Mcf. (Item F: Ex. 18-2, Sch. 11.)

All witnesses rely on AAQ figures. The staff, AGD, and the producer group each made certain minor adjustments to the AAQ body of data, some of which adjustments apply to regulatory expense. The staff adjustments appear to be reasonable and proper, and the Examiner will follow the staff presentation.

The producer group say that regulatory expense has been greater annually than it was in the test year, 1962, when *Permian* was being tried. (Prod. Br., 213.) The Examiner is unable so to find in the absence of evidentiary support for their assertion Also, the amount of the expense is not the whole picture—the sales volumes have been greater since 1962. If the net result entitles the producers to a higher allowance they should produce the requisite proof.

The Examiner allows 0.14 per Mcf for regulatory expense.

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Return Allowance

Return on Production Investment. The *Permian* method of determining return on net investment develops an average net-investment rate base on the assumption that the reserves found as a result of the successful investment will be produced in equal annual volumes over a 20-year period. Thus, the average dollar of production investment will remain unrecovered for a period of 10 years from the beginning of production. *Permian* also takes into account the fact that there is a delay or lag—assumed to be one year—between the average timing of production investment and the beginning of production. (34 F.P.C., at 199-200.) The return allowance on net investment which reflects these conditions

is determined by multiplying the production investment (the sum of the allowances for successful wells, lease acquisitions, and other production facilities) by 11 years; and multiplying this investment base by the allowed rate of return. (34 F.P.C., at 204.) In *Southern Louisiana*, the Commission again employed this method of calculating return on net investment. (Opinion 546, mimeo., 37-44, 50.) The Examiner follows these precedents.

The producer group continue to criticize the basis on which the return allowance is calculated under *Permian* methodology. They claim that such approach, among other things, ignores the time value of money, improperly portrays cost and revenue timing relationships, and employs an understated rate base. In essence, the producers continue to urge the adoption of a discounted cash flow analysis in costing new gas-well gas (referred to as the DCF or project method), instead of the method approved by the Commission in *Permian* and *Southern Louisiana*. (Prod. Br., 46, 57-61, 64-76.) The Examiner rejects the producers' approach.

In elaboration upon the reasons for his action, the Examiner incorporates by reference mimeo. pages 81 to 121, inclusive, and Appendix D, of the initial decision in *Hugoton-Anadarko*. Certain pages and paragraphs of this material contain or pertain to figures, specific cost findings, forecasts, unit-cost levels, and results peculiarly applicable to the cost of new gas-well gas in the *Hugoton-Anadarko* proceeding. These portions of the material are incorporated, not in showing the cost of new gas-well gas in this proceeding, but solely in support of the finding that properly constructed *Permian*-method costing and DCF costing yield compatible results. (The Examiner makes an independent analysis of the unit costs here involved.) The portions of the *Hugoton-Anadarko* material incorporated for the limited pur-

pose are as follows: (1) the phrase on page 83, line 10, reading, "as shown in Appendix D hereto"; (2) the portion of the

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initial decision commencing at line 10, page 92, with, "This finding," and continuing to the end of the first full paragraph on page 94; (3) the last paragraph on page 94; (4) footnote 1 on page 100; (5) Appendix D to the decision.

From the Examiner's foregoing determinations, it follows that the investment base herein prescribed is 11 times the production investment (the sum of the allowances herein for successful wells, lease acquisitions, and other production facilities); and the return on investment, 10 ½% of the investment base. The production investment has been found to be 4.33¢ per Mcf. The resulting investment base is 47.63¢ per Mcf; and the return allowance, hereby adopted, is 5.00¢ per Mcf.

Return on Working Capital. The Examiner calculates working capital in the new-gas costing by (1) a traditional utility allowance, consisting of the sum of one-eighth of expenses, plus prepayments and materials and supplies; and (2) a "lease play" equal to 1.5 times the allowance for lease acquisitions. A return is allowed on this working capital computation. *Permian*, 34 F.P.C., at 204-06, and *Southern Louisiana*, Opinion 546, 51-52, are governing precedents.

The producer group continue to argue for a working-capital allowance by "a variation of the balance sheet approach," on the basis of exactly the same evidence which they adduced in *Southern Louisiana*. The Commission there rejected such argument in a holding which is dispositive of the question. (Opinion 546,mimeo., 51.)

Application of the *Permian* formula to this proceeding and adjustment of Loring's Exhibit 20, Schedule 7, to reflect the costs found herein for production operating expense, E&D allowance, and lease acquisition costs, result in the traditional utility allowance of 1.599¢ per Mcf and a lease-play allowance of 1.965¢ per Mcf. The return on total working-capital allowance at a 10.5% rate of return in calculated to be 0.37¢ per Mcf for new gas-well gas.[27]

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Royalties

The staff and AGD recommend a royalty of 14%. Producer witness Sherwin reached a general conclusion, not based on any particular study, that the royalty cost should be a minimum of 15%, due to what he claimed was an "upward trend in royalties." (9:1032-33.)

Staff witness Lewis, AGD witness Roseman, and producer witness Auten made royalty studies. The Examiner prefers a royalty study to the general estimate of Sherwin.

The AAQ data which underlie the various royalty studies permit the royalty percentage to be calculated either on a volumetric basis or a revenue basis. The data show a somewhat higher royalty percentage on a revenue basis than on the former basis.

The producers take the position that the calculation should be made on a revenue basis. (Prod. Br., 117.) In his initial decision in *Southern Louisiana*, Examiner

[27] The Examiner's computation of the new-gas cost includes a separate classification for working capital. In the development of a composite cost of service for flowing gas, the working-capital allowance is not set out separately but is combined with investment in property under the separate cost comuptation for production and E&D costs.

Zwerdling concluded that this basis is preferable (mimeo., 108) but the Commission did not pass on the question. In their initial decisions in *Hugoton-Anadarko* (mimeo., 145) and *Texas Gulf Coast* (mimeo., 155), Examiners Kane and Taylor adopted the revenue basis. This Examiner agrees that the revenue basis is better than the volumetric.

On a revenue basis, the witness' calculated royalty percentages are 14.1% by Lewis, 14.4% by Roseman, and 15.7% by Auten. The AAQ groups used by these three witnesses include pipeline companies. The pipeline data should be eliminated. In *Southern Louisiana*, at mimeo. page 60, speaking of the royalty percentage there recommended by Auten, the Commission said, "The 15.7 percentage is inflated to begin with, because it includes pipeline royalties . . . ." In Lewis' sample, elimination, of the atypical pipeline data reduces the royalty percentage from 14.1% to 13.54% (Item A: Ex. 63-J, Sch. 1.)

Aside from variance in their AAQ samples, the three witnesses differ primarily in that Lewis and Roseman deduct, or net out, total royalty receipts, whereas Auten deducts no royalty receipts. In their brief, the producers concede that overriding royalties should be deducted in an industry-wide study, but argue that fee royalties should not be deducted. (Prod. Br., 117-18.) The Examiner agrees with this position. Fee royalties are payments to a landowner (in this case one who is a producer) whose costs of owning such royalty are not reflected in the "new-gas" cost. In the Lewis sample, inclusion of the fee royalties raises the 13.54% by only 0.3% or 0.4%. (9:1121-22.)

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The Examiner concludes that a royalty percentage of 14% is a sufficient and adequate allowance. Application of this percentage royalty in the new-gas costing in this proceeding results in a unit royalty figure of 2.11¢ per Mcf. Production taxes chargeable to the royalty owner are not included in this amount.

Production Taxes

The producer group correctly state: "In each of the prior area rate proceedings, as to both new and flowing gas costing, the production tax allowance was based on the actual state production taxes paid in each area respectively. The rate design witnesses in this case honored this well-reasoned precedent. This procedure should be followed by the Examiner in this case." (Prod. Br., 213.)

The practice is to show a nationwide new-gas-well-gas costing with an illustrative nationwide production tax; and then, in the design of area rates, to employ the actual state tax. Both the staff witness and the producer witness use an illustrative 7% tax (Ex. 3-A, Sch. 2; Ex. 20), which the Examiner also employs. Sherwin has estimated, however, that the nationwide average production tax is probably less than 7%. (Ex. 3-A, Sch. 13.)

Based on the unit costs herein adopted, a production tax allowance calculated at 7% amounts to 1.14¢ per Mcf. This amount includes the royalty owner's share of the production tax. (*Southern Louisiana, Opinion* 546, mimeo., 58.)

Summary of Nationwide Cost of New Gas-Well Gas

The total nationwide cost of new gas-well gas determined herein is calculated to be 16.22¢ per Mcf, as appears in the following table:

Depreciation, Depletion and Amortization (DD&A)	
Successful well costs	2.69¢
Lease acquisitions	1.31
Other production facilities	0.33
E&D	
Dry holes	1.41
G&G and lease rentals	1.36
Exploratory overhead	0.39
Adjustment for exploration in excess of production	1.17
Production Operating Expense	2.70
Return on Production Investment	5.00
Return on Working Capital	0.37
Net Liquid Credit	(3.90)
Regulatory Expense	0.14
Subtotal	12.97
Royalty @ 14 Percent	2.11
Production Tax @ 7 Percent	1.14
Total	16.22¢

V. COST OF FLOWING GAS

In *Permian*, the Commission determined the historical cost of flowing gas by reference to the composited test-year (1960) cost and production experience of 67 "Appendix B" respondents to that proceeding. (34 F.P.C., at 212-214.) The costing was limited to the cost of gas-well gas, on the ground that no realistic cost of oil-well gas could be determined. (34 F.P.C., at 210-212.)

The cost so determined was comprised of four elements: production cost, E&D, regulatory expense, and production tax. Differing from the costing of new gas-well gas, no separate allowance for royalty was necessary, since the flowing-gas unit costs were developed on net working-interest basis. (34 F.P.C., at 218, n. 40.) The Commission did not include any costs of off-lease gathering or processing of gas-well gas.

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The production cost in turn included (1) production operating (cash) expense, (2) DD&A of production investment, and (3) return on a production rate base comprised of net production investment and production working capital. The E&D cost included (1) exploration and development expense and (2) a return on an exploration and development rate base comprised of E&D net investment and E&D working capital. (34 F.P..C, at 214, 216, 218, 301.)

The production cost for flowing gas-well gas was determined on an area basis (34 F.P.C., at 213), and was limited to costs incurred on three lease classes: (1) gas-only, (2) gas-condensate-with-lease-separation, and (3) gas-condensate-without-lease-separation. The Commission excluded combination leases even though gas-well gas is produced on such leases. (34 F.P.C., at 295-296.) In arriving at the overall average unit cost of gas-well gas produced from the three lease classifications employed, it was first necessary to allocate the joint costs on gas-condensate-with-lease-separation leases between the two lease products—gas-well gas and condensate. The Commission employed the relative-cost method; and, in so doing, used area single-product "legs." However, the question whether to use nationwide legs

in allocating area joint costs in other area rate cases was left open. (34 F.P.C., at 298-300.)

In deriving the relative-cost ratios, the Commission excluded shut-in leases from the gas leg and oil leg. Return on joint net investment was allocated on the basis of single-product gross investment. (34 F.P.C., at 300-301.

The E&D cost for flowing gas-well gas was determined on a nationwide basis. In the determination, the Commission allocated total E&D among all lease products—oil, gas-well gas, casinghead gas, and condensate—using the modified Btu method. The adopted unit cost reflected the overall average E&D cost for total gas-well gas production, including production on combination leases. (34 F.P.C., at 217-18, 302-03.)

In *Southern Louisiana*, the Commission relied on the *Permian* approach to the costing of flowing gas. It again used the modified Btu method to allocate nationwide E&D costs. In addition to production cost, E&D cost, regulatory expense and state production tax (where applicable), the Commission allowed certain gathering costs. These included the cost of separate gathering systems —*i.e.*, gathering systems not connected to extraction plants, where the costs are not included in the producers' lease costs—and an allocated portion of the cost of gathering to extraction plants. (Opinion 546, mimeo., 82.) The Commission stated its reason for allowing the gathering costs, explaining that in *Permian* gas-well gas was customarily

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delivered at or near the wellhead, while in *Southern Louisiana* delivery is made at the tailgate of a plant or at a central point in the field. (*Ibid.*, mimeo., 61.)

In determining the cost of flowing gas, the Examiner follows the *Permian* and *Southern Louisiana* precedents.

Preliminary Questions

AGD Argument That All Flowing Gas in Area Should be Costed. AGD argues that in costing flowing gas it is improper only to determine the cost of gas-well gas and to impute such cost to all other flowing gas, *viz.*, casinghead gas and residue gas derived from old gas-well gas or casinghead gas. They advocate both a gas-well costing and an all-gas costing in establishing rates for flowing gas. Even if rates for flowing gas are set on the basis of the cost of flowing gas-well gas, they say that the cost of all flowing gas (the combined allocated cost of gas-well gas, casinghead gas, and residue gas) should be used as a test of the revenue requirements from flowing gas in the area. (AGD Br., 31-33.)

The difficulty with AGD's position is that the Commission has twice held—in *Permian* and *Southern Louisiana*—"that no realistic cost of oil-well gas either as casinghead gas or residue gas can be established"; and hence has rejected the use of a purported cost of all flowing gas for setting rates for flowing gas. (*Permian*, 34 F.P.C., at 211, 212; Opinion 546, mimeo., 24-25, 64 and App. E, p. 1.) By the same token, no realistic cost of oil-well gas can be obtained for the purpose of testing the revenue requirements for flowing gas. No new facts or circumstances have been presented which bring the instant proceeding without the holdings in *Permian* and *Southern Louisana*. The Examiner is bound by those holdings.

Gas-well gas costs alone will be determined here, and the rates derived from such costs will be applied to casinghead and residue gas.

Body of Cost Data. The cost of flowing gas-well gas as determined by the staff is based on the composite data

for independent producers (including production affiliates of pipeline companies) as reported on the AAQ. The producer group take the position that cost data of AAQ pipeline producers should be used as well. The producer group argue that in the pending *Pipeline Producers Area Rate Proceeding*, Docket No. RP66-24, the Commission may decide that the pipelines are to receive the area rate or some modified form thereof; therefore, that "the pipeline costs should be included in the cost composites used [in this proceeding] to determine the area rates." (Prod. Br., 143-44.)

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The Examiner disagrees with the producer group. The phase of *Pipeline Production*, Docket No. RP66-24, now in issue is to determine two question: (1) whether the Commission should depart from the cost-of-service method of fixing the price of pipeline produced gas; and (2) what is the proper method to be used in pricing new gas-well gas produced by pipelines. (See order instituting proceeding, 35 F.P.C. 497, 499, 500.) The producer group's argument, based on a premise as to what the Commission may decide in that proceeding, is sheer speculation. The instant proceeding should not be decided on speculation.

Futhermore, assuming, for the purpose of the discussion, that sometime the Commission were to decide in *Pipeline Production* that the pipelines should be given the area rates which will here be allowed, for new gas and old gas, it does not follow that the cost data of the AAQ pipeline producers are material in the instant proceeding. This proceeding is one to fix rates for sales in interstate commerce by independent producers. The question is, "What rates are proper for independent pro-

ducers?" The rates should be fixed on the basis of the costs of independent producers, not the costs of pipeline companies. If the Commission were to decide in *Pipeline Production* that the natural gas produced by pipelines is to be priced at the area rates allowed herein —the assumption the producer group ask the Examiner to make—the Commission would merely be applying the independent producer rates to pipeline companies. The Commission would not and could not change the fact that the rates fixed herein are rates for independent producers.

The proper place to consider the AAQ pipeline cost data is the *Pipeline Production* case, the proceeding specifically instituted to determine the appropriate method to be used in pricing natural gas produced by pipelines.

Position of Hunt Group. The Hunt group take the position that small producer costs must be considered in fixing area ceiling prices for flowing gas. Relying on testimony of Jim K. Trout, an accountant, they claim that the AAQ covers only 60.58% of Other Southwest Area production volumes, and that the remainder "was obviously produced by the smaller producers." (Hunt Br., 9.)

In an attempt to determine the cost impact of the inclusion of small producers, Trout looked to nationwide data filed in *Permian* and *Southern Louisiana* under 1960 cost questionnaires. The questionnaires were not mandatory for small producers, and only 119 of them responded with completed questionnaires. (9:1281, 1283-84.) According to Trout's findings, in 1960 these 119 small producers experienced an average flowing-gas-well-gas.

cost of 19.40¢ per Mcf. Trout imputes their 1960 average gas-well gas production and exploration cost to the 1962 nationwide production volumes not reported in the AAQ and combines the result with the 1962 costs incurred by the AAQ respondents. The result is a total nationwide cost of 14.7¢ per Mcf, as compared with the 13.3¢ cost experienced by the AAQ respondents. (9:1288.) Since the Commission's area rate determination "will be applied to sales by all producers, large and small," the Hunt group argue that the higher costs of the small producers shown by the Trout presentation should be reflected in the production and exploration cost component used in fixing flowing-gas area rates. (Hunt Br., 11.)

The contention of the Hunt group must be rejected for several reasons. First, the Trout presentation purports to determine costs on a nationwide basis, not on an area basis. The Examiner has found, consistent with *Permian* and *Southern Louisiana*, that flowing-gas costs should reflect area production costs. There is no evidence in the record showing the production costs of small producers in the Other Southwest Area. Nor is there any evidence that such production costs differ significantly from those of the AAQ respondents.

Second, even if production cost for flowing gas-well gas were properly to be determined on a nationwide basis, the sample of 119 small producers is inadequate for the purposes intended. These producers account for only about 15% of the industry small-producer nationwide volumes for 1960. (9:1284.) Moreover, the sample is heavily oriented to the Permian Basin and Southern Louisiana Areas. The sample contains only small pro-

ducers whose total operations include operations in one or both of such areas. Of these, only 21 (9:1281) are among the some 700 small-producer respondents to this proceeding.[28] Hence, the composited "nationwide" cost and production data used by Trout is unduly weighted by experience in the Permian Basin and Southern Louisiana Areas, as contrasted with data derived from a sample of small producers selected randomly, without regard to particular production areas.

Third, Trout weights the AAQ and non-AAQ producer-group unit costs for gas-well gas in proportion to the respective total gas production volumes of each group. (9:1288.) Such

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weighting necessarily assumes that the ratio of gas-well gas production to total gas production is the same for both groups—a fact not established in the record.

Fourth, Trout relies heavily on *Permian* and *Southern Louisiana* Appendix C questionnaire responses, designed for small producers. Of the 119 responses he employed, over three-fourths were from these questionnaires—69, from the Permian Appendix C questionnaire; and 27, from the Southern Louisiana Appendix C questionnaire. (9:1281.) The Commission found the Appendix C data filed in *Permian* to be inadequate even for purposes of determining small producer Permian Basin Area production costs, "because the percentage coverage of the small producers was not large nor was the sample random." (34 F.P.C., at 214.) The Commission found

[28] Employing the Hunt group's premise that those producers who did not respond to the AAQ were "the smaller producers," there were 737 "smaller" producer respondents to this proceeding when it was instituted (795 independent producers minus the 58 who filed responses to the AAQ).

a similar frailty respecting the Appendix C data in *Southern Louisiana.* (Opinion 546, mimeo., App. E, p. 6.)

Miscellaneous Minor Adjustments to Basic Data. There are minor differences in the composites of AAQ data relied on by the staff and by the producer group, apparently the result of differing minor adjustments to the raw data. One diversity is that the staff witnesses credited miscellaneous lease revenues to operating expenses, whereas the producer witness did not. The effect is a difference of 0.2¢ per Mcf. (13:1809, 1812.) In the Examiner's view, the staff treatment is proper. Miscellaneous revenues include, among other things, revenues from the sale of sulphur and other depletable minerals found with oil and gas, and incidental revenues related to treatment on the lease of oil, gas, and condensate for others; and do not include any condensate or extracted liquid revenues. (Item A: Ex. 51-J; Instructions to the AAQ, Sch. H.)

The remaining differences are *de minimis.* Staff witness Albert F. Bass states that the other adjustments have a combined effect resulting in a difference of less than 0.10¢, and producer witness Auten says that none of the minor differences in the basic data is of particular significance. (13:1802, 1810.) Hence, respecting these adjustments, the Examiner will follow the staff presentation.

Functionalization and Allocation of Overhead Costs

The Examiner incorporates by reference the first three paragraphs on mimeo. page 160 of the initial decision in *Hugoton-Anadarko.*

There is no issue concerning the functionalization of overheads to operating department or separation between the Other

Southwest Area and other pricing areas. However, an issue arises regarding the proper treatment of overhead costs functionalized to the production department. The AAQ was sent out prior to issuance of the *Permian* opinion. Some of the AAQ respondents allocated these overhead investment and expense itmes to lease classes on bases different from that thereafter prescribed in *Permian*, and the staff reallocated them in a manner designed to conform the data to the pattern prescribed by that opinion. The staff's reallocations had the effect of reducing the gas costs by approximately 0.2¢ per Mcf on a unit basis in the Other Southwest Area. (13:1812; Ex. 39, line 4, cols. (1) and (2).)

The producer group object to the reallocations. They contend that where the respondent companies reported their production overhead investment and expense items by lease classification, such allocations are to be accepted. (Prod. Br., 164, 168.) In support of this contention, first they note that by the AAQ instructions, all companies were ordered to allocate or assign their production costs, including overheads, to lease classifications. (*Ibid.*, 167.) This fact is immaterial. Despite the AAQ instructions, the allocations which the companies made are not binding upon the Examiner and the Commission especially since the Commission in *Permian* has now set out the approved allocation.

The producers further say that there are understandable differences among the various systems used by the reporting companies in spreading their respective production overhead expenses and investments over the applicable lease classifications; that each company selected its own system, depending on the individual characteristics of its operations and on its own accounting proced-

ures; and that tampering with one aspect of the system affects the rationale supporting the whole. (*Ibid.*, 168.) These averments also are immaterial. None of such circumstances relieves the producers from following the method of allocation prescribed in *Permian*.

The producers further say that in *Southern Louisiana* the Commission recognized that where respondent companies had reported their overhead investment and expense items by lease classification, no reallocation by formula is necessary, citing the following language from that opinion: "Staff also assigned production overhead investment and expense and materials, supplies, and prepayments to the various lease classifications where the respondent companies did not do so." (*Ibid.*, 164.) The producers misconstrue *Southern Louisiana*. The quoted language merely refers to the action of the staff at the time they prepared their case in *Southern Louisiana*. The *Permian* opinion had not then been issued, and the standards announced in that

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opinion were not available as a guide or precedent.

The producers suggest that the Commission in *Southern Louisiana* appears to have modified slightly the position taken in *Permian* respecting the prescribed basis of allocation. (*Ibid.*) Inasmuch as the Commission expressly states in *Southern Louisiana* (mimeo., 72) that the overhead allocations "are consistent with our prior determinations in Opinion No. 468," the producers' suggestion is of no force.

Finally, the producer group contend that the reallocation procedures in the instant case have an added complication by virtue of the fact "that the hearing area in this case includes six separate guideline pricing areas

(the area breakdown used for the AAQ), and was subdivided into three proposed pricing areas by Staff"; and that "the question immediately arises on what area basis will the reallocation ratios be calculated." (Prod. Br., 165-66.) Suffice it to say that the producers cite no evidentiary presentation supporting a method different from the staff's for handling the reallocations, nor do they suggest what cost impact would result from adoption of any such different method.

Cycling Lease Data

The producer group argue that cycling lease data should be excluded from the cost calculation. Exclusion of these data would increase the staff's unit cost by about 0.5¢ per Mcf. (13:1812; Ex. 39, line 4, cols. (1) and (3).)

The producer group state: "In *Permian* [34 F.P.C., at 297] and in *Southern Louisiana* [mimeo., 72-73] the producers advocated that the volumes which were reinjected be excluded from the cost calculations. The Commission rejected this approach in Opinions 468 and 546, reasoning that where the costs attributable to the reinjected volumes were included, but the volumes were excluded, the result was an overstatement of unit cost. In this case, however, producers urge, not that the volumes alone be excluded, but that the cycling lease data, both costs and volumes, for the phase 1 and phase 2 operations, be excluded in estimating the unit cost for gas. Therefore, there is no overstatement of the unit cost of the gas remaining." (Prod. Br., 145.)

The producers took this same position in *Texas Gulf Coast*, and Examiner Taylor rejected it. (Mimeo., 173-78.) This Examiner agrees with Examiner Taylor.

The producers err in contending that under their approach

no overstatement of the unit cost of gas results. The record shows that substantial volumes of gas were produced on cycling leases and sold. Of total area gas lease production of 673.3 million Mcf, 77.0 million Mcf, or 11.4%, was reported on cycling leases. (Ex. 5, Schs. 19, 20.) Assuming 5% fuel and shrinkage loss, a reasonable estimate of the total sales from cycling gas-condensate-lease-separation leases, and cycling gas-condensate-no-lease-separation leases, is 43.3 million Mcf, or over 56% of the total production of 77.0 million Mcf from these leases. Such sales constitute 6.4% of the area total gas lease production. Treating of a similar factual situation in *Texas Gulf Coast*, Examiner Taylor used language applicable here: ". . . the producers' method would result in excluding substantial quantities of low cost gas from the total unit cost calculation." (Mimeo., 175.)

The producers further contend that the cycling lease data should be excluded because of difficulty in allocating joint costs between oil and gas, the reason given by the Commission in *Permian* for not including the costs and volumes of producing gas from oil reservoirs in the cost calculations. They aver, "the problems in allocating costs between liquids and gas on a cycling lease exceed those encountered on a casinghead gas lease or combination lease." (Prod. Br., 147.) This position is erroneous. The finding of Examiner Taylor in *Texas Gulf Coast* is true here: "Insofar as the cycling leases are concerned, . . . there is no necessity for either a two-step allocation procedure or reliance on a calculated unit cost of casinghead gas. For this reason, the producers' alleged analogy between cycling leases and combination leases is inapposite." (Mimeo., 178.)

Allocation of Production Cost by Relative-Cost Method

In *Southern Louisiana*, the Commission explained the relative-cost method of allocating production cost, here followed:

> "The rationale of the relative cost method is that the joint costs relating to production of both gas and condensate should be allocated between these co-products on the basis of the costs of the separate production of liquid hydrocarbons relative to the separate production costs of gas.
>
> "The cost of separately producing liquids and gas involves a determination of the cost per barrel of commercial lease liquids from oil only leases (the oil leg), and the cost per Mcf of gas on gas only leases (the gas leg). The unit cost of liquids is then divided

> by the unit cost of gas. The result of this division is termed the relative cost ratio, since it provides the unit cost of lease liquids relative to the unit cost of lease gas. The liquid element of this ratio is then multiplied by total condensate production from gas condensate lease separation leases, and the gas element of the ratio is multiplied by total gas production volumes from the same lease category." (Opinion 546, mimeo., 74.)

In arriving at the relative-cost ratio, four questions are here presented; *viz.*, (1) whether gas-condensate-no-lease-separation leases should be included in the composition of the gas leg; (2) whether area legs or nationwide legs should be adopted; (3) whether shut-in leases and shut-in wells should be excluded from the legs; and (4) whether water production volumes should be included in the allocation procedure.

Composition of Gas Leg. The producer witness, Auten, includes gas-condensate-no-lease-separation leases in the composition of the gas leg, along with gas-only leases. (9:1114-17.) Staff witness Raymond D. Murr and AGD rebuttal witness Larson limit the gas leg to gas-only leases. (9:1218-21; 13:1837.) The Examiner rejects the producer approach in this respect on the authority of *Southern Louisiana*: ". . . inclusion of the gas condensate without lease separation leases is inconsistent with the very principle of the relative cost method, ..." (Opinion 546, mimeo. 75.)

Area or Nationwide Legs.—The producer group use area legs; the staff, nationwide legs. Again, the staff's position prevails upon the authority of *Southern Louisiana.* There, in adopting national legs, the Commission said at mimeo. page 75:

> ". . . national legs provide a broad basis for determining the relative cost of separately producing lease liquids and separately producing gas. . . . The question is whether the national ratios are proper for use in deriving area costs. . . . The allocation ratios involve only the apportioning of reported area costs between gas and condensate. We think the use of national ratios for this purpose is fully warranted, especially where the available data do not permit development of reliable area ratios."

And further, at page 76:

> "In our opinion a gas leg containing Respondents' costs of production in all geographical regions of the continental United States, including the Southern Louisiana

> area, provides representative, stable cost ratios, expressing the relationship between the average cost

> of producing a barrel of lease liquids with virtually no gas and an Mcf of gas with virtually no liquids. Our conclusion is that the national single product ratios developed by the staff provide the best basis for the allocation of Southern Louisiana joint production costs."

The language there used respecting the Southern Louisiana Area applies equally well to the Other Southwest Area.

In the instant proceeding, from a volumetric and percentage standpoint, area legs are usable. The 1962 area gas-only lease production for independent producers and pipeline affiliates was 60.0 million Mcf. Total area gas lease production was 673.3 million Mcf; and total area gas production from all leases, 1,041.6 million Mcf. Thus, area gas-only lease production was 8.9% of total area gas lease production, and 5.8% of total area gas production from all leases. (Ex. 14, Sch. 1.) This gas-only lease production, with these percentages, is sufficient for development of an area leg. *Cf. Permian*, 34 F.P.C., at 299.

Nevertheless, as seen from *Southern Louisiana*, use of national legs is "fully warranted," and is to be preferred.[29] As there indicated, the national legs provide a broader sample; and the broader the sample, the better

[29] Prior to *Southern Louisiana*, the Commission expressed the view, in *Permian*, that ". . . where an area gas leg is derived from dry gas volumes of 41,652,569 and where the use of national dry gas production would produce a result equivalent to the use of the area dry gas production, we believe it is proper to use the area production leg." (34 F.P.C., at 300.) There was no substantial issue in *Permian* whether to use national or area legs, because virtually the same result followed in either case—use of nationwide gas only production yielded a production cost of 9.136¢ per Mcf; use of Permian Basin production resulted in a production cost of 9.157¢ per Mcf. (*Ibid.*, at 299.) Whatever be the effect of *Permian*, the Examiner follows the latter opinion, *Southern Louisiana*.

the relationship developed. National legs are less likely to suffer from wide variation due to atypical individual companies or atypical lease experience. They are more likely to result in a relatively stable measurement of the relationship between the costs of

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producing gas and liquids. Finally, a general use of national legs in area rate proceedings provides a standard indicator of the relative cost of producing the single products, liquids and gas.

The producer group, and the Hunt group and Superior separately, contend that the nationwide gas leg is unduly influenced by production from the Hugoton-Anadarko Area. This same argument was made and rejected in *Southern Louisiana.* (Opinion 546, mimeo., 75-76.)

Staff witness Raymond D. Murr shows that use of area legs would result in a unit production cost approximately 0.6¢ higher than does use of nationwide legs. (9:1221.)

Shut-in Property Adjustment. For allocation purposes, the staff's presentation excludes from the legs, shut-in leases; but does not exclude shut-in wells on producing leases. The producer witness excludes both. (9:1219; 13:1811.) The staff presentation is adopted upon the authority of *Southern Louisiana.* (Opinion 546, mimeo., 76-78.)

Inclusion of Water Production Volumes. The producer group, through their witness Auten, propose an adjustment to the oil leg by adding the water production to the oil production. In the test year, some 88% of the total liquid production by AAQ companies on nationwide oil-only leases was water. (Prod. Br., 158.) The effect of the water-volume adjustment is to reduce the oil-only unit cost determination. (Ex. 6, Sch. 11.) The staff and AGD oppose this adjustment.

The proposed adjustment is wholly without merit. The evidence shows that the water is a noncommercial, waste product. (21:2742; Item A: 121:17,478, 17,482.) The cost arising from its production and disposal is included in the oil-only lease costs; and is properly borne by the commercial product, the oil, as reflected in the exhibits of the staff witnesses. (Item A: 121:17,479.) See, *e.g.*, Harold G. Avery, "Accounting for Joint Costs," *The Accounting Review*, XXVI (1951), 236. The producers' attempted "allocation" of costs between the oil and the waste matter is a violation of accounting principles, an economic absurdity, and a dissimulation.

The producer group aver that in deriving the allocation ratio, the issue of which liquid product on the oil only category must ultimately bear the costs, has no significance. (Item F: T-7: 558; H-14:1640; Prod. Br., 158, 161.) This assertion is erroneous. As stated by AGD witness George E. Tyler, "If you do not determine the cost of gas and cost of oil on the single product leases, you do not determine anything meaningful for the relative cost method." (Item A: 76:11,877.)

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The producer group further seek to justify use of the water volumes in computing the oil leg by arguing that the staff-proposed relative cost ratios are based on the gas-well volumes produced and on the oil-well volumes sold; and that the staff's use in the gas leg of unsold gas-well volumes entitles the producers to use in the oil leg the volumes produced of both oil and water. (Prod. Br., 158-59; Prod. Rep. Br., 50.) This strained argument falls down. The contention is premised on the assertion that the gas leg obtained by the staff included inert gases, which were not sold; and reinjected gas, which

was not sold in the test year. (Prod. Rep. Br., 50; Item A: 121:17,480.) As to the inert gases, the premise is erroneous. Although the inerts referred to are not commercial hydrocarbons, they are present in small amounts (21:2770, 2773) in the gas stream when it is sold. (21: 2749.) It is misdescriptive to say that the inerts are not sold.

Assuming for the purpose of the discussion that the staff committed an error of consequence by including in the gas leg a quantity of unsold inert gases and unsold reinjected gas, the proper recourse would be to adjust the gas leg by removing therefrom such unsold quantities. Instead, the producer group immensely compound the error by using it as an excuse to load the oil leg with seven times as much water as oil.

Ignoring other deficiencies in the producers' argument last referred to, a sufficient answer to it is that *de minimis non curat lex.* It has been noted that the quantity of inerts is small. The reinjected gas comprises only about 0.02% of the volume produced on nationwide gas-only leases. (Computation from Item A; Ex. 51-J, Sch. 5.) Removal of this volume from the gas leg would have no effect on the relative-cost ratio.

The producer group make an "alternative" argument that at least a portion of the water production should be included in the oil leg. This portion consists of water volumes reinjected into the formation to increase the production of oil. (Prod. Br., 160; Prod. Rep. Br., 50.) Such argument is invalid. As explained by Bass, the effect of producing more oil by reinjection of water was to reduce the unit cost on the oil leg. This fact is automatically taken into account in determining the relative cost of production of oil and gas. Hence, to add the reinjected water to the oil leg amounts to a "doubling up." (21:2786, 2794.)

Lastly, the producer group seek to surround their position with an aura of fairness by proposing to use water volumes along with condensate volumes in allocating costs on gas-condensate-lease-separation leases. (Prod. Br., 159; Prod. Rep. Br., 51.)

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This proposal is rejected for the same reasons that the producers' water-in-oil-leg proposal is rejected.

The differences between the position of the producers and that of the staff and AGD respecting the inclusion of water-production volumes in the oil leg and in the gas-condensate-lease-separation leases would result in an increase in the staff's unit cost of 2.041¢ per Mcf. (36: 3950; Ex. 39.)

Summary of Unit Production Cost

The unit production costs of flowing gas from gas-only and gas-condensate leases for the Other Southwest Area, at a 10½% rate of return, based on cost calculations of staff witnesses, are found by the Examiner to be justified. These costs, both for the Other Southwest Area and as broken down by such witnesses into underlying areas, are as follows:

Other Southwest Area (consolidated)	8.10¢
Mississippi	9.57
Northern Louisiana	8.11
East Texas/Arkansas	6.88
Texas R.R. District No. 5	8.24
Texas R.R. District No. 9	14.18
Other Oklahoma-Arkansas	9.52

Exploration and Development Costs

In *Southern Louisiana*, mimeo. pages 67-68, the Commission sets out an exposition of the nature of exploration and development costs; the necessity for an allocation thereof between gas and liquids; the Commission's adherence to the computation of the E&D allowance on a nationwide basis; and the propriety of the modified Btu method of allocation, adopted in *Permian*. The Examiner follows *Permian* and *Southern Louisiana* and applies the modified Btu method. In so doing, he rejects arguments of the producer group, detailed below.

The producer group rely on their evidentiary presentation in the joint proceeding, except in one respect. There, 11 companies voluntarily furnished evidence of a direct assignment by them of exploration and development costs to oil and gas. Evidence of a similar nature is here presented by a twelfth company, Humble. (9: 1124-31.)

All parties have computed the E&D costs on the basis of 1962 nationwide E&D expenditures incurred and reported by the respondents to the AAQ. There is no significant disagreement as to the dollar amount of the E&D costs.

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The staff and AGD advocate allocating all E&D costs by the modified Btu method, following *Permian* and *Southern Louisiana*.[30] The producer group contend that the evidence presented by them in the joint record and here

[30] The staff also show an alternative calculation which reflects a preliminary assignment of development dry-hole costs, based on AAQ Schedule F-5 responses, prior to application of the modified Btu method. Reliance on Schedule F-5 data is unwarranted. See *infra*, pp. 87-88.

warrants a different approach. They seek to make a direct assignment of a portion of the E&D costs to oil reservoirs and gas reservoirs; to allocate the remainder of such costs to reservoir types by methods hereinafter referred to; and to limit a modified Btu method to allocating, between gas-well gas and liquids, the costs so aggregated to gas reservoirs. The producers contend that their proposals accord with a basic cost concept that costs which can be identified or assigned should be segregated and not allocated. (Prod. Br., 170.)

The producers' approach will now be more particularly described and its result shown. In Exhibit 6, Schedule 16, producer witness Auten sets out total E&D costs of AAQ producers and pipeline affiliates amounting to approximately $1.45 billion, and an assignment and allocation procedure which results in the aggregation of these total costs between oil reservoirs and gas reservoirs. In a second step, the costs aggregated to gas reservoirs are then allocated between gas-well gas and liquids on the basis of a modified Btu employing a factor of 3.5 to weight the liquids Btu's.

In aggregating costs between oil reservoirs and gas reservoirs, Auten starts with the direct assignments of the 12 companies. These respondents claimed to have identified a substantial portion of their E&D costs (including exploratory and developmental dry-hole costs) to reservoir types. Their assigned costs amount to approximately $443 million, or 30%, of the total AAQ company E&D costs. The assignments break down to approximately 48% to oil reservoirs and 52% to gas reservoirs.

There remain to be allocated to reservoir types approximately $1,012 million of E&D costs, which include unassigned costs of the 12 companies and all the costs of the other AAQ producer and pipeline affiliates. Auten allocates development dry-hole costs included in this

amount to reservoir types on the basis of data from AAQ companies reported in Schedule F-5 of the AAQ. He allocates all other remaining E&D costs on various

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"successful efforts" bases. Thus, the $1,012 million of unassigned E&D costs are allocated approximately 55% to oil reservoirs and 45% to gas reservoirs.

The result of Auten's assignment and allocation of costs to reservoir types aggregates $684 million to gas reservoirs, or 47% of the total nationwide E&D costs of the AAQ companies. The further allocation of the costs so aggregated to gas reservoirs, using a modified Btu method with an economic factor of 3.5, results in a unit E&D allowance for flowing gas of 9.63¢ per Mcf at a 12% rate of return.

Bearing in mind that in terms of volume of revenues, income, and sales, the independent producers are primarily oil companies (Item A: 78:12,230; 86:13,093), it seems incongruous that nearly one-half of all the E&D costs should be borne by gas. From this "end result," a grave question arises as to the validity of Auten's method of dividing these costs.

In a proper case, a direct assignment of identifiable E&D costs is preferable to the use of allocation formulae. But a case is not proper unless there be an adequate evidentiary foundation to sustain the validity of the data used. Due to the absence of a uniform system of accounting and to the fact that the direct assignments of expenses between gas and oil reservoirs are based upon subjective standards, assurance of the objectivity and disinterestedness of such assignments must be required as a prerequisite to their acceptance and adoption. Otherwise, as is apparent from the evidence, differences in

the reporting standards of the individual companies, plus self-interest determinations involved, render the data unsuitable for rate regulation.

The data furnished in Schedule F-5 of the AAQ are not a random sample of the development dry-hole costs of the AAQ companies. Only 46% of the total development dry-hole expenses incurred by 69 AAQ companies was properly reported by lease classification as requested in the AAQ; 33% was improperly reported by reservoir type; and 21% was unreported as between oil and gas. The failure to report, or properly to report, 54% of the total developmental dry-hole costs by lease class justifies the conclusion that, as in *Permian*, 34 F.P.C., at 217, "there was a considerable degree of self-selection" in the data reported by the producers. Not being a random sample, the data "do not offer a reliable foundation for fixing prices." *Ibid.*

The failure of the AAQ companies properly to report 54% of the total developmental dry-hole expenses, and the self-selection involved in the 46% sample, raise a strong suspicion

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that the sample does not properly represent the industry pattern of development dry-hole cost incurrence by lease class. It is likely that there is a distortion and unfair tilt in using the percentages developed from this sample to allocate development dry-hole costs to lease classes.

The evidence produced respecting the direct assignment of exploration costs by the 12 companies has similar and even graver flaws. These voluntary filings are self-serving in that they are made by only a limited number of the producer companies. The data are not shown to be representative of the industry, and they are not the result of random sampling of the producers. Moreover,

AGD adduced evidence from which the Examiner finds that the direct assignments are tilted toward an increase in the cost allocable to gas. The Examiner finds and concludes that the data supplied in Schedule F-5 and the evidence of the 12-company direct assignments are deficient and unsuitable as a basis for determining an element of cost in fixing the price of flowing gas.

Furthermore, the allocations which were based on successful-efforts methods lack an adequate basis in that the producers have not presented their reserve data. In *Southern Louisiana*, the Commission held that these data are necessary to test such allocations. (Opinion 546, mimeo., 70.)

For these several reasons, the Examiner concludes that the producers' assignment and allocation of costs to reservoir types cannot be accepted.

Economic Factor to be Used in Modified Btu Method. In *Permian*, the Commission based its determination of the economic factor to be used in allocating flowing-gas E&D costs on, *inter alia*, a value relationship reflecting the value of lease liquids, natural gas, and the Btu content of each. In valuing natural gas, the Commission looked to the price established for new gas-well gas. (34 F.P.C., at 217.) The Commission arrived at "a value relationship of a Btu of liquids to a Btu of gas-well gas of 3.45 to 1," and concluded that an economic factor of 3.5 should be adopted. (34 F.P.C., at 217-18.)

In this proceeding, the nationwide new gas-well gas cost has been found to be 16.22¢ per Mcf. The test-year Btu ratio of a barrel of lease liquids to an Mcf of gas is 5.2. (Item A: 76:11,675; 71:10,626.) The test-year value of a barrel of lease liquids is $2.90. (Item A: Ex. 51-J, Sch. 7.) Making the *Permian* type of computation with the foregoing figures, the Examiner finds that the value relationship of a Btu of liquids

to a Btu of gas-well gas is 3.44 to 1[31]—substantially the same value relationship found by the Commission in *Permian*. Upon the authority of *Permian*, the Examiner finds and concludes that in this proceeding, likewise, the proper economic factor to employ is 3.5.[32]

Application of this economic factor results in an E&D allowance of 4.01¢ per Mcf for gas-well gas. (Item A: Ex. 55-J, Sch. 1, sheet 1.) This amount is included in the costing for flowing gas herein.

Regulatory Expense

The Examiner allows 0.17¢ per Mcf for regulatory expense in flowing-gas costs. It has been seen that the allowance herein for this expense in new-gas costs is 0.14¢ per Mcf. Flowing-gas cost computations are on a net working basis, whereas new-gas costs are based on gross-interest volumes. The difference between the two reflects a royalty interest of 14%.

The allowance of 0.17¢ is the figure shown both by staff witness Fell and producer witness Auten, after adjustment of Auten's calculations to reflect a 14% royalty and a 10½% rate of return. (Item A: 71:10,584; Item F: Ex. 18-2, Sch. 11.)

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[31] The price ratio of $2.90 per barrel of liquids to 16.22¢ per Mcf of gas is 17.88. Dividing this ratio by 5.2 yields a value relationship of 3.44.

[32] The record in this proceeding does not permit the evaluation or quantification of the other factors mentioned by the Commission in *Permian* in arriving at the economic factor.

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VI. PRICING AREAS

The staff, the producer group, and George Mitchell & Associates, Inc., each make a recommendation for the division of the Other Southwest Area into pricing areas. Staff witness Engel recommends three areas; *viz.*, Pricing Area 1—other Oklahoma, northern Arkansas, and Texas District No. 9; Pricing Area 2—Texas Districts Nos. 5 and 6, southern Arkansas, and northern Louisiana; Pricing Area 3—Mississippi (onshore and offshore) and northwest Alabama (Marion, Fayette, Lamar, and Pickens Counties).

Producer witness Dr. J. Rhoads Foster recommends four pricing areas; namely, (1) Mississippi, the four Alabama counties, and five parishes in the southeast portion of northern Louisiana (Catahoula, Concordia, Franklin, LaSalle, and Tensas); (2) northern Louisiana (exclusive of the five parishes); (3) Texas Districts Nos. 5, 6, and 9, and southern Arkansas; (4) other Oklahoma and northern Arkansas.

GMA advocates that Texas District No. 9 be constituted a separate pricing area.

Consideration of Recommendations

Staff Proposal. In the Examiner's opinion, the recommendation of the staff should be adopted, except for the inclusion of offshore Mississippi in Pricing Area 3. Engel recognizes that there is "no happy formula" for the composition of the pricing areas. (42:4486-87.) With the exception of offshore Mississippi, his recommendation is an exercise of judgment based on analysis of geology, marketing, cost incurrence, and pricing patterns. The Examiner's reasons for adopting Engel's division of the

Other Southwest Area (except for offshore Mississippi) into pricing areas are in the main stated in the staff witness' testimony, and are in part based on other evidence.

The "starting points" are the pricing areas within the Other Southwest Area contained in the Commission's Statement of General Policy No. 61-1, issued in 1960, as amended in 1960-64 (embodied in Section 2.56 of the *Rules of Practice and Procedure*)—as tentatively revised in a Notice of Proposed Rule Making, Docket No. R-218, issued June 11, 1962. The areas thus tentatively revised were used by the Commission in collecting cost and other data under the AAQ.[33] They are: (a) northern

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Louisiana; (b) Texas District No. 6 and 12 counties in southern Arkansas; (c) other Oklahoma and northern and central Arkansas; (d) Mississippi and the four counties in Alabama; (e) Texas District No. 5; and (f) Texas District No. 9.

The Examiner recognizes that the Statement of General Policy and the tentative revision thereof are not dispositive of the issue of proper pricing areas. That issue is an open question, to be determined in this proceeding. However, the areas delineated in the tentative revision of the Statement of Policy serve as appropriate starting points.

As to Engel's Pricing Area 1: Other Oklahoma, Texas District 9, and northern Arkansas fall into a common general geological grouping. In these three subdivisions, the oil and natural gas production is from rocks of Pale-

[33] By order issued November 27, 1963, the Commission postponed indefinitely adoption of final revisions to the proposed pricing areas, pending analysis of AAQ data and decision in area rate proceedings.

ozoic age. The three subdivisions are separated from the remainder of the Other Southwest Area by a discrete dislocation of the basement rock. They serve as both a supply and marketing area for several major pipelines. The pricing patterns in these subdivisions are substantially similar. (20:2677.)

As to Engel's Pricing Area 2: In Texas Districts 5 and 6, southern Arkansas, and northern Louisiana, the production is from the younger Mesozoic and Cenozoic rocks. The pricing history indicates that the combination is appropriate. (20:2678.) The three subdivisions constitute a general supply area for pipelines. In general, the production in the subdivisions is old; some of the major fields are quite old. (41:4376.)

As to Engel's Pricing Area 3: As hereinafter shown more particularly (*infra*, p. 100), there is a significant difference between Pricing Area 2 and Pricing Area 3 in average Btu. In 1966, in Pricing Area 2, the weighted average Btu of the natural gas sold to pipelines was 1032; in Pricing Area 3, 986—a difference of nearly 50 Btu. This difference is a factor justifying the division of the territory comprising Pricing Areas 2 and 3 into these two pricing areas.

In treating the whole of Mississippi (onshore) and the counties in northwest Alabama as one pricing area, the criterion of a common geological grouping is departed from; geology divides the State of Mississippi. Practical considerations warrant this departure. The available geological and cost data

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are insufficient to permit a comparison of the flowing gas cost in northern Mississippi with that in southern Mississippi. Furthermore, the northern portion is relatively

undeveloped compared with the southern portion. Because of convenience and pricing history, the entire State and the Alabama counties may appropriately be treated as a unit. (20:2678; 35:3892.)

The propriety for pricing purposes of the three areas is further indicated by analysis of the drilling cost data, investment-cost relationships, production data, and reserve data. (Ex. 60, Schs. 9, 10; 20:2676, 2677; 41:4351-53, 4356-57.)

Turning to offshore Mississippi: These lands on the continental shelf (both state and federal) were specifically made part of the Other Southwest Area by order issued December 8, 1967. The little evidence respecting them suffices to compel the conclusion that they do not belong in Pricing Area 3. There is no production offshore from Mississippi, so there is no basis for making a comparison of marketing and pricing patterns with onshore Mississippi. Moreover, cost incurrence offshore will not be comparable with that onshore. Beebe testified that, because of severe exploration problems and high cost of solving them, there has been little exploratory drilling offshore from Mississippi (three test holes); but that cooperative reconnaissance seismic surveys using modern sophisticated equipment techniques are now being conducted. (9:960.) The record is silent upon the question of the extent to which the high costs of exploration and development offshore may be counterbalanced by higher productivity.

Plainly, there is no justification for making offshore Mississippi a part of Pricing Area 3. Either it should constitute a separate pricing area; or Area Rate Proceeding (Off-shore Southern Louisiana Federal Domain and Disputed Areas), Docket No. AR69-1, should be broadened to include offshore Mississippi.

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Presiding Examiner's Initial Decision

There is insufficiency of evidence to prescribe just and reasonable rates for offshore Mississippi. The Examiner does not attempt to do so. Among other things, as already noted, there is no history of cost of exploration and production and volume of production. On cross-examination, Engel could not make a recommendation respecting certain essentials of a just and reasonable rate; and suggested that "the best way to handle this is to await the Commission's decision in regard to South Louisiana . . . and very possibly that any future Mississipi well offshore should be handled in the same manner." (43:4520.)

As further reason for the suggestion that Docket No. AR69-1 be enlarged to encompass offshore Mississippi, inspection of

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U.S. Geological Survey Map NH 16-4 reveals that offshore Mississippi is very small in area compared to adjacent offshore Louisiana. Furthermore, Roy T. Durst, a petroleum engineer testifying on behalf of respondent Richardson Oils, Inc., said that "geologically there is no reason why the structures similar to those that have been found off the coast of Louisiana should not also be found off the coast of Mississippi. . . . We are in the same geologic province." (6:783.) This testimony was uncontradicted. When an adequate record is made, the Commission may conclude that the same rates (except for tax difference should be set for production offshore Louisiana and Mississippi.

Producer Group Proposal. It will be seen that there are three differences between the proposals of producer witness Foster and staff witness Engel: (1) Foster includes the five Louisiana parishes in the Mississippi area instead of northern Louisiana; (2) Foster combines

Texas Districts 5, 6, and 9, whereas Engel groups District 9 with other Oklahoma and northern Arkansas; (3) Foster recommends four pricing areas, constituting northern Louisiana (other than the five parishes) a separate area.

Of these differences, the first is the major subject of contention between the producer group and the staff. The five northern Louisiana parishes are part of a producing aera which extends into adjacent Mississippi. The Mississippi portion of the producing area is in the counties of Jefferson, Adams, Wilkinson, and Franklin. Sales contracts cover the production in both States. (20:2625; Ex. 1, Map 4.) In the northern Louisiana portion, respondent The California Company makes one of the largest sales in the Other Southwest Area to Southern Natural Gas Company—almost 25 million Mcf in 1966; and in the Mississippi portion, makes another sale, 1,400,000 Mcf in 1966, at the same price, to the same pipeline purchaser. (Ex. 56, Sch. 1, sheet 3, Sch. 3, sheet 8; Ex. 52, Sch. 1, sheet 1, Sch. 2, sheet 10.)

Foster takes the position that the entire overlapping producing area should be assigned either to Mississippi or northern Louisiana. He recommends Mississippi, "for the reason that the price structure in the five Northern Louisiana parishes is more nealy comparable with Mississippi than with Northern Louisiana prices." (20: 2625.)

The showing, while good as far as it goes, is insufficient to enable the producer group to prevail. In the first place, there is want of evidence as to what the average unit cost of flowing gas would be in the Mississippi pricing area (including the four Alabama counties) as reconstituted by the addition of

the five Louisiana parishes.

To elucidate: the Commission held in *Permian* that a cost determination is "the bedrock on which a regulated price must be established" (34 F.P.C., at 189-90), "the basic ingredient in determining the area rate" (*Ibid.*, at 190), the "basic yardstick" (*Ibid.*, at 212). Again, in *Southern Louisiana*, the Commission stated that ". . . composite costs must provide the basis for ultimate prices." (Opinion 546, mimeo., 24.)

Upon the authority of these opinions, cost is the benchmark in the ceiling rates adopted herein. As shown *infra* (pp. 117-22), the Examiner determines an average unit cost of pipeline quality flowing gas in each of the three prescribed pricing areas of the Other Southwest Area. These average unit costs are based, *inter alia*, upon the cost and volumetric data from the AAQ, utilizing procedures developed by Engel. Upon the average unit cost for the respective pricing areas, the rates for flowing gas herein fixed are predicated.

There is no way of ascertaining from the record what the reconstituted average unit cost would be for an area comprised of Pricing Area 3 (as prescribed herein) plus the five northern Louisiana parishes. As already seen, under the AAQ the Commission collected cost and volumetric data for northern Louisiana as a unit. There is no separate data in the record for the five northern Louisiana parishes. If, as the producer witness recommends, the five parishes were assigned to Mississippi (including the Alabama counties), there would necessarily be a departure from a cost basis in establishing rates for such pricing area—in violation of *Permian* and *Southern Louisiana*.

In the second place, the cost-price relationship in Pricing Area 2, as prescribed herein) would also be upset. With the five parishes withdrawn from Pricing Area 2, there is no way of determining what the reconstituted average unit cost would be for the remaining portion of such pricing area, in the absence of separate cost and volumetric data for these parishes.

The only way, on the record made, for the northern Louisiana part of the producing area in question and the Mississippi part of such area to be in the same pricing area, would be to combine Pricing Areas 2 and 3 into one huge pricing area. In the Examiner's view, a ruling so requiring would not be justified.

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Had the producer group been minded so to do, they could have properly put in issue the question of the propriety of carving the five parishes out of northern Louisiana and assigning them to Mississippi. In order to raise the cost issue, they should have made a motion to the Examiner for a special data request, directed to the respondents who filed the responses to the AAQ utilized by the staff in compositing their cost data. The special data request would have sought 1962 cost and volumetric data for the five parishes in northern Louisiana and the four counties in Mississippi comprising the production area. After consideration of all pertinent evidentiary factors in the record, the Examiner could have reached a conclusion as to whether it would be more appropriate to assign the entire producing area to Mississippi, as Foster recommends; or, on the other hand, to northern Louisiana. Having made this decision, the Examiner could have determined the average unit cost of flowing gas for the reconstituted pricing areas from

the cost and volumetric data filed in response to the special data request. Thus, lawful ceiling rates in the premises for the reconstituted pricing areas could have been prescribed.

Turning to ceiling rates for new gas-well gas: There is no need to go into the question whether the record is sufficient to determine what the unit cost of pipeline quality new gas-well gas would be in Pricing Areas 3 and 2, respectively, if the entire producing area involved were assigned to Pricing Area 3. Such question is moot. As developed hereinafter (Appendix G), the only significant difference in the new gas rates herein prescribed for northern Louisiana and Pricing Area 3 is accounted for by the substantially higher production tax applicable in Louisiana. In this connection, note the statement of the Commission in *Permian*, 34 F.P.C., at 206: "We think that reasonable local taxes are a valid basis for a difference in ceiling prices between one area and another and if reasonable the tax applicable to each state should be applied to the gas produced in that state."

Respecting the second difference between the producer witness and the staff witness, in the Examiner's judgment, Texas District 9 properly should be made part of a pricing area composed of such district, other Oklahoma, and northern Arkansas. As heretofore found, the production from all this region is from

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Paleozoic rocks. On the contrary, the oil and gas found in Texas Districts 5 and 6 and southern Arkansas are Mesozoic and Cenozoic production. Beebe's testimony shows, as recognized by Foster, that District 9, other Oklahoma, and northern Arkansas, combined, constitute one of the three producing reigons in the Other South-

west Area. (20:2618-19.) Certain price and production volume considerations advanced by Foster as reason for combining District 9 with Districts 5 and 6 (20:2625-26) are insufficient to overcome the geological considerations.

Respecting the third difference between the two witnesses, the weight of the evidence is against making northern Louisiana a separate pricing area.

GMA Proposal. George Mitchell & Associates, Inc., seek special treatment—a separate pricing area for Texas District 9. GMA takes the position that this district should receive higher rates than the rest of the Other Southwest Area because of claimed higher costs resulting from "fundamentally different" geological characteristics. (GMA Br., 2-3.) The evidence in support of GMA's case does not satisfy the Examiner's mind. Also, position is opposed by cogent evidence. To particularize:

First, it has already been shown that northern Arkansas, other Oklahoma, and Texas District 9— Engel's proposed Pricing Area 1—constitute one of three producing regions in the Other Southwest Area. He who would justify carving a separate pricing area out of this producing region has a had row to hoe.

Secondly, the evidence in support of the claim of higher costs in Texas District 9 is not persuasive. GMA asserts, based on an exhibit presented by an accountant, R. W. Goodman, Jr., that in 1962 the cost of gas produced from District 9 was in excess of 20¢ per Mcf. (*Ibid.*, 3.) Goodman shows an average gas revenue in such district in that year of 11.50¢. (Ex. 24, Sch. 1) One wonders why producers would sell 20¢ gas for 11¢. On cross-examination, asked to explain, the witness replied that he had made no cost determination "of my own"; "I am not saying this is the cost of producing gas in these areas"; but under the *Permian* method of determining cost, "this is the answer you would get." (23:3024-25.)

Both the staff and AGD witness Larson point out that the GMA witness has costed only about a fourth of the gas-well gas produced in District 9, and they consider the purported cost of over 20¢ per Mcf, resulting from this sample, to be unrepresentative and inappropriate for Texas District 9 rate-design purposes.

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(Staff Rep. Br., 73-74; 27:3330.) Goodman's exhibit is based on cost and volume data reported in the AAQ. The explanation for the small percentage reported is that GMA, who acts as operator for producers making over 70% of the jurisdictional sales to pipelines in the district, petitioned for and was granted exemption from AAQ filing requirements. (Ex. 52, p. 90, col. (t), lines 23 plus 24, divided by p. 91, col (t), line 17; Item N.)

Staff witness Engel said that the coverage cost data for Texas District 9, "indicates higher cost there than in Other Oklahoma-Arkansas." However, he further said, and the Examiner finds, that the coverage is relatively poor; that little or no cost data were reported for the Boonsville area, where the reserves are old, shallow, and presumably less costly. The cost per foot of drilling and contract prices indicate that the AAQ costs for District 9 are not reflective of the general level of costs. (20: 2678.) Furthermore, Larson testified that a proper revenue-cost determination for Texas District 9 would show that both costs and revenue are about 14¢ per Mcf (27: 3330.) [34]

Thirdly, in the view of Robert A. Harris, GMA's geological witness, only the Fort Worth Basin, in the

[34] The average price realized by producers in District 9 for jurisdictional sales to interstate pipelines was 14.89¢ per Mcf in 1962. (Ex. 60, Sch. 7, sheet 3.)

southeastern part of District 9, is fundamentally different from the remainder of the Other Southwest Area. (23:3031-32.) Note in this connection the findings respecting the geology of Texas District 9 and adjacent Oklahoma, *supra*, page 11. Stratigraphic conditions and related structural features have localized most of the gas accumulation in District 9 in the Fort Worth Basin. The basin is only some 200 miles in length and from a few miles to nearly 100 miles wide. (9:1307.) It would take an extraordinary situation, if any, to justify making a pricing area of territory of that size. The Commission simply cannot have a separate rate structure for every little area. To do so would tend to defeat the purpose of area regulation and would be administratively infeasible. Beebe testified, and the Examiner finds, that the Oklahoma portion to the Arkoma Basin is "a classic study in exploration incongruities," and that exploratory well drilling in that basin is "extremely costly." (9:965-66; 15:2093.) Would not GMA's approach to rate design entitle that region, as well, to be made a distinct pricing area? Again, Beebe testified, and the Examiner finds, that in the Arkoma Basin of Arkansas, dry hole and development costs are higher generally

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than they are in the remainder of the Other Southwest Area, because of difficulty in terrain, hardness of the beds, and costly drilling. "This is an extremely difficult area. The vegetation is bad. There are few roads. It is difficult to get around. The rocks are hard, there are hard rocks on the surface." (15:2127-28.) Is that region, as well, to be carved out of Pricing Area 1 as a separate pricing area? To follow GMA's approach would stand to result in breaking Pricing Area 1 into fragments. In the

interest of effective area rate regulation, such outcome cannot be countenanced.

Fourthly, the evidence introduced by GMA fails to demonstrate such geological uniqueness and extraordinary drilling expense in the Fort Worth Basin (or in District 9) as would require or justify separate treatment for pricing purposes. Other evidence refutes or tends to refute GMA's position. GMA relies principally on the testimony of Harris. His testimony shows that all significant production in the basin comes from conglomerate reservoirs found at a depth of from 5,000 to 6,500 feet. These reservoirs are erratically distributed, shoestring in shape, lenticular in cross section, and generally have limited areal extent. Hence, the reservoirs are difficult to predict even at offset locations. The permeability, porosity, and pressure of these random reservoirs is relatively low. (9:1308-09, 1320.)

According to Harris, "the chief gas areas" of District 9—*i.e.*, the Fort Worth Basin—are different from the Arkoma Basin of eastern Oklahoma and Arkansas, and from the area in other Oklahoma immediately north of it of comparable depth. In the Arkoma Basin, he testified, the producing sediments are involved in long narrow anticlines trending east-west, where there are stratigraphic traps and structural traps. (9:1313; 23:3032.) As to the former traps, he said, "I don't know that it would be fair to say they predominate." In the part of Okalahoma immediately north of District 9, the hydrocarbons are mainly trapped by folds and faults in sands and limestones. On the other hand, the chief gas areas of District 9, of depth equivalent, have different producing characteristics and trapping mechanisms; the hydrocarbons are trapped mostly by stratigraphic traps in conglomerate lenses and sands. (9:1312.) These lenses and sands are erratic. (23:3035.)

The correctness of Harris' exposition is in part confirmed by the testimony of Beebe. Speaking of the Fort Worth Basin, the producer group's geological witness said: ". . . natural gas discovered to date has been found in stratigraphic traps and there is yet no reasonably certain means of locating such traps other than by the use of subsurface geological control and the

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drill." (9:972.)

However, other testimony of Beebe overcomes the force of Harris' contrast of the Fort Worth Basin with the Arkoma Basin. Thus, Beebe said that much of the natural gas accumulated in the Arkoma Basin is found, not in structural entrapments, but in "important stratigraphic traps." (9:966.) The Examiner so finds.

The uniqueness of the Fort Worth Basin in having substantially all production from stratigraphic traps as opposed to partial production from such traps in the Arkoma Basin does not establish or indicate that drilling costs are higher in the former basin than in the latter. Beebe stated, and the Examiner finds, that the Arkoma Basin is one of the most difficult places in the entire Midcontinent to drill. (15:2093.) As already noted, Beebe's testimony shows that a prominent feature of the Arkoma Basin in Oklahoma is exploration incongruities. The incongruities, he said, exist to a lesser degree in Texas District 9. (15:2126-27.) The Examiner so finds. Beebe's testimony cited *supra* shows that exploratory well drilling in the Arkoma Basin of Oklahoma is extremely costly, and that in the Arkoma Basin of Arkansas exploration and development costs are higher generally than in the remainder of the Other Southwest Area.

Harris made no claim that the permeability and porosity of the gas-bearing portion of District 9 are lower

than in the Arkoma Basin. His testimony was that the porosity and permeability of the gas-bearing portion of District 9 are lower than "the adjacent parts of Other Southwest." By adjacent parts, he meant, "Such as the East Texas Basin on the east, the southern Oklahoma basin on the north, for example." (23:3034.)

Harris' delineation of the geological differences between the Fort Worth Basin and the southern portion of other Oklahoma is of little consequence. In the first place, the witness himself says that southern Oklahoma "produces chiefly oil." (9:1312.) In the second place, the Examiner is not satisfied that drilling is more costly in the Fort Worth Basin than in Southern Oklahoma. Beebe testified, and the Examiner finds, that the Ardmore and Marietta-Sherman Basins of southern Oklahoma are extremely difficult areas to explore with any definitive means of locating a trap, and very difficult in which to drill exploratory wells; and that the uplifts, also, constitute some very difficult drilling. (15:2094, 2129-30.)

The Examiner concludes that GMA's proposal must be rejected.

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VII. PRICE ADJUSTMENTS TO REFLECT QUALITY DIFFERENTIALS

Btu Standards

Pursuant to authoriaztion of the Examiner, the staff, on August 2, 1967, sent an Actual Conditions of Delivery Questionnaire (ACD) to 23 pipeline purchasers and 25 producer purchasers in the Other Southwest Area. The ACD called for 26 items of data, of which the pertinent one at this point in the decision is the average Btu content of the natural gas received by the respective pur-

chasers during the year 1966. The purchaser was requested to report the Btu data on an actual basis for 1966, if available; otherwise, on tests or analyses in other recent years, or on an estimated basis. (20:2640; Ex. 52, p. iii.) Responses were received from 21 pipelines and 12 producers. These responses cover in excess of 95% of the 1966 volumes purchased by pipelines in each of the pricing areas. (Staff Rep. Br., 71, App. D.)

Staff witness James W. McCarrick, Jr., presented Exhibit 52, a summary of all Btu data supplied by the pipeline purchasers. (20:2632-33.) The data include all types of gas and all delivery points. (20:2641.) Another McCarrick exhibit sets out arrays of average Btu content for gas purchased, under independent producer rate schedules, in each of Engel's three pricing areas. (20: 2641; Ex. 53.) Based on these data, the witness determined that, in Pricing Area 1, the weighted average Btu was 1061; in Pricing Area 2, 1032; and in Pricing Area 3, 986. (20:2645-47.)

The producer group attack these averages, claiming that they are based on defective data. In the Examiner's view, the data are adequate. The producers brought out on cross-examination that in Areas 1 and 2, 24.4% and 13.5% of the total volumes in the respective areas were estimated or based on commingled transmission-line samples. (39:4260; Prod. Br., 271-72.) The producers furnish no breakdown between estimates and commingled transmission-line samples, but from scanning Exhibit 52 it would seem that the latter volumes were relatively small. As to the estimates and the content values derived from tests and analyses made in years other than 1966, McCarrick said: "I think that the estimates provided by company experts and the results of tests or analyses performed in earlier or later years are far superior to a complete absence of data for a relatively large number

of sales and that when combined with the actual data available provide the best available approximation of the overall heat content of gas flowing from an area." (20: 2643.) The Examiner agrees.

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The producers argue that the Btu data shown on the ACD are not superior to the Btu data from F.P.C. Form 2 reports. (Prod. Br., 271.) McCarrick's testimony refutes this contention: "The information as provided in the Form 2's is not broken down to the point that it would be as useful as this questionnaire was. . . . I think the information we have is far superior to that which could be obtained from the Form 2's." (39:4247.)

The producers rely on statements made by representatives of three of the pipelines at a transcribed informal conference held on July 18, 1967, between the staff, the producers, and respondent pipeline companies respecting the then proposed data requests. These statements were to the effect that there were shortcomings in the Btu data in the possession of their companies. (Prod. Br., 270-71.) At the beginning of the informal conference, it was expressly "understood . . . by all that the transcript and any portion of any discussion taking place here does not become a part of the evidentiary record in the proceeding." (Tr. of Informal Conference, Docket No. AR67-1, held July 18, 1967, p. 3.) During cross-examination of McCarrick, the statements of the three pipeline people were quoted in questions put to the witness. (39:4244-45.) In view of the stipulation at the informal conference, the Examiner thinks that the quotations should be considered only as evidence that the pipe-

line representatives made the statements, and not as evidence of the correctness of their contents.

If accorded any probative effect, such statements are insufficient to sustain the producers' contention. First, they pertain only to three pipelines. Secondly, their force is refuted by McCarrick's testimony. (39:4246-47.) Thirdly, the three pipelines responded to the ACD and reported Btu values of their purchases. Fourthly, the data are appropriate for the purpose for which they are used; *i.e.*, to set broad standards for determining which sales will be subject to an adjustment—the actual Btu content for each sale will be employed in making the adjustment. Finally, not a single person, from a pipeline company or elsewhere, was called as a witness to support the producers' claim of unreliability of the Btu data composited from the ACD or to rebut the testimony and exhibits presented by McCarrick.

An abstract of data from the independent-producer rate schedules shows that the contracts for the sale of gas customarily contain a warranty respecting the minimum Btu level and/or permit the purchaser to reject deliveries having a heating value less than the stated minimum level. For Pricing Area 1, the common warranted Btu level is 1000 (52.6% of all contracts).

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In Pricing Area 2, the most common warranted Btu level is 1000 (34.1% of all contracts). In Pricing Area 3, a preponderant number of contracts (84.4%) provide a minimum Btu warranty of 950.

The bulk of the contracts do not contain a Btu price adjustment provision. In Pricing Area 1, only 179 out of a total of 603 contracts provide for a downward price adjustment from any Btu level; and only 39 provide for

an upward price adjustment. Of the 179 contracts, 156 provide for downward adjustment from 1000 Btu; all of the 39 provide for upward adjustment from 1000 Btu. Again, in Pricing Area 2, 400 contracts out of a total of 1602 provide for downward adjustment and only 1 provides for upward adjustment. Of the 400 contracts, 390 reflect a 1000 Btu adjustment base. Finally, in Pricing Area 3, 33 contracts out of 212 provide for downward adjustment and 1 provides for upward adjustment. Where downward adjustment is provided, 30 contracts employ an adjustment base of 1000 Btu. (Exs. 55-58.) Thus, in the Other Southwest Area, no customary practice has been established either for downward or upward Btu price adjustments.

Permian and *Southern Louisiana* are precedents upon the question of Btu standards in the design of area rates. In *Permian*, 34 F.P.C., at 223, the Commission said:

> "We believe the weighted average Btu content of gas-well gas in the area should generally be used as the guideline for upward adjustments. . . . we shall permit an upward Btu price adjustment from a base of 1,050 Btu's per cubic foot. . . . The record also reveals that a minimum standard for pipeline quality gas in the Permian Basin is 1,000 Btu's per cubic foot. . . . We shall accordingly provide a downward adjustment for new gas-well gas from a base of 1,000 Btu's . . . ."

In *Southern Louisiana*, the pertinent language is:

> "It has been customary in this area as well as in most of the nation to provide for downward adjustment of price only where the Btu content of the gas falls below 1,000 Btu's. . . . we will provide that no downward adjustment of the base area rates shall be made by reason of Btu content unless that content falls below 1,000 Btu's. . . ."

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"No Btu standard as a base for upward adjustment of prices has been established in Southern Louisiana, by custom or otherwise. It has not been the usual practice in the area to provide for any upward adjustment in price by reason of high Btu content. The 1,000 Btu content commonly required by contracts in the area is a minimum standard only. It is not an indication of average quality—in fact, the average Btu content in the area was close to 1,050 on the basis of 1960 and 1961 statistics. On the basis of statistics from the pipelines' 1966 Form 2 reports, the average Btu content measured at the point of purchases has decreased somewhat and is now approximately 1,037 Btu per cubic foot. These statistics indicate a downward trend. An area rate bonus for gas of superior quality should be allowed only for gas which is above the average in Btu content. Accordingly, we believe an upward adjustment of the base area rate should be made only where the Btu content of the gas exceeds 1,050." (Opinion 546, mimeo., 91-92.)

It will be seen that, in both of these opinions, the Commission employed a standard which contained a range within which no Btu price adjustment was to be made; that in both opinions, in setting the upper end of the range, the Commission looked to the weighted average Btu of actual deliveries; and that, in setting the lower end of the range, the Commission in *Permian* looked to the contractual "minimum standard for pipeline quality gas," and in *Southern Louisiana*, looked to the contractual level "customary in this area" from which downward adjustments were made.

Sound reasons in this proceeding, as well, for having a range or zone of no price adjustments appear from

McCarrick's testimony. If both upward and downward Btu price adjustments were to be made from the same level,

> "such a procedure would require price adjustments, either upward or downward, for essentially all gas from the area and would in effect convert the area rate to a price per Btu or per therm basis instead of the traditional volumetric pricing. Such a procedure would also require, I think, a finding that the calculated weighted average figure for each area was sufficiently precise to justify adjustments from that level." (20:2644.)

Furthermore, the record discloses that over time, it is to

be expected that the weighted average Btu content for each of the pricing areas will change "to some extent," but not "a great deal." (39:4264.) Adoption of standards which contain zones of no adjustment tends to mitigate problems arising from these changes; and also arising from minor fluctuation in Btu content of individual deliveries, and from any imprecision in measurement techniques. For these reasons, the Examiner concludes that the Btu standard should contain a zone in each pricing area for which no adjustment is required.

There is no problem in applying the rule of *Permian* and *Southern Louisiana* to the evidence in the proceeding respecting the upper end of the range in the respective pricing areas. However, a question arises concerning the lower end of the range. Does the evidence that the contracts customarily contain warranted Btu levels of 1000 in Pricing Areas 1 and 2, and 950 in Pricing Area 3, justify fixing the lower end of the range at these respective levels? Since the warranty provisions are not pro-

visions for downward adjustments, they do not literally meet the test which the Commission used in *Southern Louisiana* in specifying the lower end of the range. However, the reason for the contractual provisions respecting warranties is the same as those respecting downward adjustments. In each case, the parties purchaser to the contracts seek to protect themselves against having to pay the contract price for gas of less than a certain Btu content. By analogy to *Southern Louisiana*, the Examiner concludes that it is proper to provide that no downward adjustment of the base area rates shall be made by reason of Btu content unless that content falls below the "commonly warranted" Btu level in the pricing area.

Permian is perhaps a broader holding than *Southern Louisiana*, for in *Permian*, the Commission, in speaking of the "minimum standard for pipeline quality gas" provided for in contracts, may have been referring to warranty provisions as well as price adjustment provisions. In any event, the facts here are within the reason for the rule of *Permian* and the rule of *Southern Louisiana* —to insure that the applicable base area rate will apply only to gas of a certain minimum quality in Btu content, the minimum quality to be determined by contractual standards customary in the area.

In view of the facts here involved and the precedents of *Permian* and *Southern Louisiana*, the Examiner will provide for the following Btu standards:

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(1) Pricing Area	Btu per Cubic Foot (2) Maximum	(3) Minimum
1	1060	1000
2	1030	1000
3	990	950

The increase in the applicable area rate for a given sale will be proportionate to the amount by which the Btu content exceeds the figure in column (2). The decrease in the applicable area rate will be proportionate to the amount by which the Btu content is less than the figure in column (3).

Staff witness McCarrick recommended Btu standards for the pricing areas which differ from the foregoing. At the time McCarrick testified, the Commission opinion in *Southern Louisiana*, of course, had not been issued. McCarrick recognized that his Btu adjustment recommendation did not follow *Permian*. (39:4282.) He explained his method by stating that he analyzed the data "to determine what I shall refer to as the zone of average gas. By this I mean the range of Btu values spanning the weighted average preferably in the vicinity of 50 Btu's such as the Commission adopted in *Permian*, within which the bulk of the volumes fall." (20:2644.) In each pricing area, his zone centers around the average Btu in the area. His method is about like that adopted in the Examiner's initial decision in *Southern Louisiana*. The standards that McCarrick recommends are:

	Btu per Cubic Foot	
Pricing Area	Maximum	Minimum
1	1075	1025
2	1050	995
3	1000	950

Since the Commission in *Southern Louisiana* declined to

follow the method employed in the initial decision (Opinion 546, mimeo., 91), perforce this Examiner cannot adopt McCarrick's method. However, the Examiner feels

that as applied to the facts here presented, the approach taken by the staff witness yields a more equitable result than the approach of the Commission in *Southern Louisiana* and here followed by the Examiner; and that the Commission may see fit to adopt the staff approach. In Pricing Area 1, under the holding herein, following *Southern Louisiana*, 42.88% of the volumes are eligible for upward adjustment and 1.68% are subject to downward adjustment. Under the staff approach, only 16% of the gas would be subject to upward adjustment; and about 2%, to downward adjustment. In Pricing Area 2, under the standards herein followed, 42.82% of the volumes are subject to upward adjustment; and 21.28%, to downward adjustment. Under the staff approach, only about 27% would take an upward adjustment, and about 13%, a downward adjustment. In Pricing Area 3, under the holding herein, 13.85% of the volumes would be eligible for upward adjustment, and no volumes would take a downward adjustment. Under the staff approach, only about 6% of the gas would take an upward adjustment; and none, a downward adjustment. (20:2646-47; Ex. 53.)

The producer group recommend that 1000 Btu per cubic foot be adopted as the standard in Pricing Areas 1 and 2, with upward and downward price adjustment from that level for gas having a greater or lesser heat content. For Pricing Area 3, they recommend that no specific standard be established by order; and, instead, that there be reliance on the contracts themselves. In the Examiner's opinion, these recommendations are unrealistic and inequitable. Upward and downward adjustment from a level of 1000 Btu in Pricing Area 1 would mean that less than 2% of the volumes delivered would carry a downward price adjustment, whereas more than 98% would be subject to upward price adjustment.

In Pricing Area 2, such standard would result in downward price adjustment for about 23% of the volumes; and upward price adjustment, for about 77%. (Ex. 53, Sch. 1.) It should be observed that the same 1000 Btu standard, if applied to Pricing Area 3, would result in downward price adjustment for about 93% of the volumes and upward adjustment for only about 7%. As already noted, the producers do not propose upward and downward adjustment from 1000 Btu in that pricing area. Instead, they would let the contract provisions operate, with the result that there would be relatively little Btu price adjustment in such area. (Ex. 55.)

The producer group cite a Notice of Proposed Rule Making, Docket No. R-200, issued by the Commission in 1961. (Prod. Br., 264; 26 Fed. Reg. 4614.) This notice is irrelevant. After interested parties responded to the notice, Docket No. R-200 lay

dormant until June 27, 1969, when the Commission dismissed the proceeding.

Next, the producers rely on *Texaco Inc., et al.*, 33 F.P.C. 1228. That case is not applicable. An omnibus producer certificate proceeding, it involved the question of the propriety of Btu adjustment provisions in relation to the in-line price at which sales should be certificated. The Commission adopted a 1000 Btu base "as representing the in-line conditions for areas herein"; and took pains to say, "We do not, of course, express any opinion as to the appropriate base for area rate purposes." (P. 1236.)

The producer group argue that the existence of a "gap" in the Btu standard will defeat the public interest objective by encouraging processing of gas down to the

lower edge of the gap, thus reducing the Btu content of the gas delivered to pipelines. (Prod. Br., 272-73.) This argument is not borne out by the facts. As a matter of actual practice, the producers in the Other Southwest Area have generally delivered gas at Btu levels considerably in excess of warranted minimums. Thus, in Pricing Area 1, it has been noted that the commonly warranted Btu level is 1000. Seventy contracts contain no warranty as to minimum Btu, and only 23 contracts warrant a Btu level higher than 1000. (Exs. 55, 58.) Yet, as heretofore found, the weighted average heating value of gas delivered to pipelines in Pricing Area 1 in 1966 was 1061 Btu per cubic foot.

Lastly, the producer group point out that where upward price adjustment is from a standard Btu level higher than the standard Btu level from which downward adjustment is calculated, the amount of upward price adjustment in cents per Mcf is less for a quantity of gas having a heat content with a given number of Btu's above the maximum standard than the downward adjustment would be for gas having a Btu content the same number of Btu's below the minimum standard. From this premise, they argue that application of a method of Btu adjustment employing a zone of no adjustments is unfair. (Prod. Br., 273-74.) The producers' premise is correct, but their conclusion is a *non sequitur*. It has been shown that under the Btu standards here adopted, in each pricing area a much larger volume of gas qualifies for upward Btu price adjustment than is subject to downward price adjustment. The same statement is true, in lesser degree, under the staff's proposed Btu standards. (See *supra*, p. 106.) With either set of standards, it is clear that the total dollars of upward Btu price adjustment would exceed by a considerable margin the dollars of downward Btu price adjustment.

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Other Quality Standards

Staff witness Engel recommends that certain "other quality standards"—specifications in addition to the Btu standards—be adopted for pipeline quality gas in each pricing area in the Other Southwest Area. These standards are as follows:

Quality Specification	Limitation
Total sulphur (grains per Mcf)[a]	200
Hydrogen sulfide (grains per Mcf)[a]	10
Water (pounds per Mcf)[a]	0.007
Carbon dioxide (percent by volume)	3
Other impurities	Commercially free
Delivery pressure to be made available by seller above	Operating pressure

[a] Mcf measured at 14.73 psia and 60°F. (Ex. 60, Sch. 2, sheet 1.)

The producers take no exception to these quality standards and AGD apparently would accept them. (50:5405-06; AGD Br., 49.) The standards prevail in the majority of contracts under which gas is sold in each of the pricing areas, and the Examiner finds them to be reasonable. (20:2688.)

In the staff's proposed rate design, the gas is fully costed to provide for generating the necessary pressure to overcome the operating pressure of the pipelines. Because of the substantial variance of operating pressure among the pipelines in each of the pricing areas, the adoption of a specific numerical pressure standard is administratively infeasible. (20:2689.)

The staff propose that the "other quality standards" apply both to existing and future contracts. The pro-

ducer group oppose the standards being made applicable to existing contracts, by which term is apparently meant contracts dated prior to issuance of the Commission's opinion and order determining just and reasonable rates herein. (Prod. Rep. Br., 134.) In the Examiner's view, there is need to have the quality standards made applicable to existing contracts as well as to future ones.

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The record discloses that significant volumes of gas purchased by pipelines in the Other Southwest Area in 1966 (especially in Pricing Area 2) did not meet the standards which the staff recommend. Out of total pipeline purchases of sligthly over 1 billion Mcf, approximately 340 million Mcf were wet; about 75 million Mcf contained excessive carbon dioxide or other impurities—*i.e.*, nitrogen; over 4 million Mcf were sour; and over 100 million Mcf were compressed by the buyer. (Ex. 54-A.)

The producers point out that in *Southern Louisiana* the Comission found it unnecessary to make quality standards (other than Btu) applicable to existing contracts. There, the situation was different; the gas flowing under existing contracts was gerenally of pipeline quality. (Opinion 546, mimeo., 85.) The Examiner finds and concludes that in the instant proceeding, application of the "other quality standards" to existing contracts as well as future contracts is reasonable and proper.

The staff advocate that fixed deductions in the rates be imposed by order in the event the "other quality standards" are not met. The deductions they recommend are based on staff analysis of the applicable functional costs within plants, staff review of applicable charges as shown in contracts, and actual deductive charges reported in the ACD. (20:2682-86.) The proposed deductions are as follows:

Sour gas	1.00¢ per Mcf
Wet gas	0.25¢ per Mcf
Acid (CO_2) gas	1.00¢ per Mcf
Operating pressure	
Area (1)	1.50¢ per Mcf
Area (2)	1.25¢ per Mcf
Area (3)	0.85¢ per Mcf

(Ex. 60, Sch. 1.)

The producer group oppose the staff recommendation. They contend that the price deductions for below-quality gas should be left to the contracting parties to negotiate instead of being fixed by Commission order. The Examiner agrees with the producer group, upon the authority of *Permian*, 34 F.P.C., at 225, 1071; and *Southern Louisiana*, Opinion 546, mimeo., 93. As the Commission stated in *Permian* on rehearing, at 1071:

> "We emphasize our desire to encourage agreement between the parties as to the proper amounts to be paid or deducted for quality adjustments. While we do not intend to permit the agreements between producers and pipelines to be used for the purpose of establishing artifically low processing costs, with

> the pipeline and ultimately the consumer making up the difference, we will approve all such agreements which reflect a good faith effort to approximate the processing costs involved, and accept for the pipelines' rate purposes the adjustments computed thereunder."

The staff say that data similar to "the comprehensive cost and gas quality data" here in evidence for determination of price ceilings and price deductions were not available to the Commission in *Permian* and *Southern Louisiana*. The fact that these data are now available does not meet the reasons the Commission assigned in *Permi-*

an for the ruling it made there and followed in *Southern Louisiana*. The availability of these data does not justify departure from those opinions.

VIII. PRODUCER PLANT AND GATHERING OPERATIONS

Staff witness Elbert O. Bateman and producer witness Carney presented cost studies on area processing plant and gathering system costs as a guide to rate design. The studies, based on AAQ responses, cover the year 1962.

Each study sets out a cost of service for numerous plants in the Other Southwest Area, on a plant-by-plant basis. The costs are shown by individual functions; *viz.*, gathering, compressing, treating, dehydration, liquids extraction, and residue gas return and delivery. The witnesses then allocate or assign, on a plant-by-plant basis, these functional costs between residue gas and plant liquids; divide the cost so allocated or assigned to gas by appropriate residue gas volumes; and thus arrive at unit cost of the gas quailty improving functions which are the result of processing plant operations. Each witness also calculates a cost of service for gas-gathering operations which are not connected to processing plants.

Gathering, treating, and compression costs are normally joint costs. Dehydration and residue gas return and delivery systems costs are usually assigned to residue gas, while liquid extraction costs are assigned to liquid products.

The principal differences between the witnesses concern these question: what method of allocation should be applied to the joint plant costs; whether plant fuel should be included as a part of the cost of processing gas; whether pipeline-owned gathering system costs should be considered in determining the gathering allowances in the area; and what rate of return should be employed?

Allocation Method

The producer group advocate a volumetric method in allocating the joint costs. (Prod. Br., 218.) The staff advocate the allocation on a Btu basis. They recommend, instead of a straight Btu basis, a modified Btu method which applies a weight of two to the Btu content of the liquid products. (Staff Br., 167.)

The Examiner rejects the volumetric method and the modified Btu method, and adopts the straight Btu method. As reason for this ruling, he incorporates by reference mimeo. page 182 and the first 10 lines on page 183 of the initial decision in *Hugoton-Anadarko.*

As additional basis for the holding, he points out that the reason for Examiner Wenner's adoption in *Permian* of a 2:1 ratio does not apply to the facts here presented. The salient operative factors here more nearly approximate those in *Phillips Petroleum Company,* 24 F.P.C. 537, 563-64, which holds that the 1:1 Btu allocation formula is appropriate for the allocation of costs to the products of the raw gas stream. The following table demonstrates the correctness of this statement:

	Permian[a]	Phillips[a]	Other Southwest[b]
Raw Gas Characteristics	Low Pressure—Rich Casinghead		
Yield			
Btu Ratio—$\frac{\text{Residue Gas}}{\text{Liquids}}$	3.05	7.10	5.62
GPM	3.44	1.49	1.77
Gas Revenues per dollar of liquid revenues	0.63	1.6	2.14

[a] 34 F.P.C. 307, 404-05.

[b] Derived for the plants in Engel's cost sample (Ex. 60, Sch. 3, sheet 7) using detail data from Bateman's Ex. 59, except that S. Sarepta and New Hope plants have been excluded.

Thus, there is no reason or justification in the instant proceeding for modification of the 1:1 Btu allocation formula employed in *Phillips*.

Bateman has calculated the allocated unit plant costs attributable to the various function, at a 10 ½% rate of return, using both the 2:1 and the 1:1 Btu methods. The results of the 1:1 Btu allocation basis, in accordance with the holding herein, are used in the rate design calculations, *infra*.

Plant Fuel Cost

The AAQ cost data do not include any charges for plant fuel (for compressing, treating, and dehydration). (20:2555-56; 35:3904; 38:4146.) Carney adds a charge for this fuel usage to his processing costs. (50:5282-83.) Engel does not do so. Engel's position is that plant fuel "is taken account of, actually, in my rate design, in a general manner"; that the plant liquid revenue either returned to the lease or retained by the plant is more than adequate to compensate for fuel cost (35:3904; 42:4427.)

In the Examiner's view, the staff position is without merit; and a component should be added to the processing costs for plant fuel, as Carney recommends. It is true that the plant liquid revenue is more than sufficient to cover fuel cost (computation in Staff Reply Brief, Appendix B), but such fact is beside the point. The cost of fuel used in compressing, treating, and dehydration is a part of the total cost of those functions. Hence, this cost should be allocated or assigned in the same way as the other costs of compressing, treating, and dehydration; *i.e.*, allocated between liquids and gas in the case of compressing and treating and assigned to gas in the

case of dehydration. Of course, the allocation and assignment of plant fuel cost pertain only to flowing gas.[35]

The record shows that fuel costs add about 20% to the other compression, treating, and dehydration costs. (50:5282-83.) In the rate design calculations, *infra*, the Examiner allows for the cost of plant fuel in that amount.

In their brief, the producers claim that Engel's plant processing costs do not inclue the cost of gathering and

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processing the plant fuel. (Prod. Br., 223-24.) This claim is erroneous. The staff's method of calucation takes account of such costs, just as does Carney's method. Carney testified that his method of allocation takes account of such costs (20:2556.) The Examiner finds that the staff's method also takes account of these costs. In rebuttal to Bateman, Carney correctly charged the staff only with failure to reflect the cost of fuel itself. (50:5282.)

Separate Gathering-System Costs

The producer group say that in determining gathering cost in his rate design, Engel ignores the cost experience of separate gathering systems. (Prod. Br., 222-23.) This averment is partially incorrect. Engel utilized the cost, of producer operated separate gathering systems carrying jurisdictional gas-well gas, as reported on the AAQ, except where the volumes of such gas were insignificant. (20:2680, 2684; 35:3895; Ex. 60, Sch. 6.)

The producer group are correct in saying that Engel did not include in his rate design study the costs of separate gathering systems operated by pipelines. His non-

[35] In the new gas-well gas costing, the cost of plant fuel is given appropriate consideration in the determination of net liquid credit.

use of such costs appears to be their chief complaint, as indicated by the subheading in the portion of their brief pertaining to separate gathering systems costs, "The Inclusion of Costs Related to the Separate Gathering Systems Operated by Pipelines in the Area." (Prod. Br., 221.)

Engel was right in not using costs of the pipeline operated separate systems. The question has already been decided generally in the holding, *supra*, page 74, that the body of cost data to be utilized in determining the cost of flowing gas-well gas is based on the composite data for independent producers, to the exclusion of cost data of pipeline producers. As there point out, the purpose of this proceeding is to set rates for sales in interstate commerce by independent producers; and the rates should be fixed on the basis of the costs of independent producers.

Specifically with reference to his proposed rate design, Engel testified that his objective was to determine "a unit cost for jurisdictional gas-well gas sales to pipelines"; that in order to include "all producer incurred cost related to jurisdictional gas-well gas, I analyzed the AAQ cost of separately reported gathering and compression systems and included such costs, where appropriate." (20: 2679-80.) And further: ". . . I am designing rates for independent producers and,

therefore, I feel it is necessary to use, where possible, independent producer costs." (43:4538.) This objective and these procedures are sound and proper.

The AAQ composite data for independent producers, employed by Engel, respecting the costs of their separate gathering systems were adequate; and the costs involved in the pipeline operated gathering systems are immaterial.

Rate of Return

The producer group argue that "the rate of return applicable to plant processing and gathering activities should be the same rate allowed on the remainder of the exploration and production function," which they claim should be 16%. (Prod. Br., 217.) The staff recommend 10 ½%. If not already passed on in setting a rate of return of 10 ½% for new gas-well gas and flowing gas *supra* pp. 14, 47), the Examiner now allows a rate of return of 10½% for the plant processing and gathering activities. The same rationale applies: such rate of return is properly fixed on the basis of the actual rates of return, from overall earnings, of the major independent producers.

Position of Associated Gas Distributors

AGD introduced Exhibit 73, which purports to show that in 1962 revenues from liquids extracted in Other Southwest Area plants exceeded total plant gathering and processing costs (at 12% rate of return) by some $3 million. Therefore, AGD argues, there is no justification for allowing recovery of any gathering and processing costs in the rates established for gas sales. (38:4156-62; AGD Br., 40.) The Examiner does not agree.

In the first place, the evidence establishes that the liquid revenues are overstated by some $2 million worth of products refined from purchased condensate. Carney correctly testified: "These products were not extracted from the gas processed at these plants. Their value cannot possibly be available as an offset to gas handling costs." (50: 5295.)

In the second place, AGD's Exhibit 73 assumes that all of the plant liquid revenues are available to offset plant costs, although, as heretofore found, some 40% of such revenue is returned to the leaseholder. (50:5298-99; *supra*,

p. 65.) Compare *Southern Louisiana*, Opinion 546-A, mimeo., 24, where the Commission said: ". . . the applicant's calculation of plant revenues fails to reflect the plant's payment of part of the

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liquid revenues to the lease. It has not been shown, then, that the plants' share of liquid revenues is adequate to cover all plant costs."

In the third place, 20 of the plants covered in Exhibit 73 have no significant commercial residue gas sales; hence their costs and liquid revenues are irrelevant. The plants in Exhibit 73, 69 in all, comprise all plants shown in the cost exhibit sponsored by staff witness Bateman. However, staff witness Engel considered roughly two-thirds of these plants to be inappropriate for gas-well gas rate-design purposes; and producer witness Carney considered nearly a third to be inappropriate for general plant costing purposes. More specifically, in his cost study, Carney eliminated 21 plants because they "delivered no significant commercial volumes of residue gas," and eliminated another because "the functional costs were not reported completely." (50:5280.)

Carney, in Exhibit 80 adjusts Exhibit 73 to eliminate 20 plants, which make few or no sales or deliveries other than for lease use. Carney said, and the Examiner finds: "These 20 plants are essentially liquid recovery operations, ... Most of them are casinghead stripper plants which recover liquids from rich oil well gas and provide fuel service to oil leases." (50:5295.) Carney further adjusted Exhibit 73 to reflect fuel, shrinkage, and loss for the remaining 49 plants.

After these proper adjustments, Exhibit 80 reflects a total cost of service (at 12% rate of return) of about

$65 million and total liquid revenue of about $53 million, a deficit of $12 million. It is needless to calculate the total cost at the 10½% rate of return allowed herein. Obviously at such a rate of return also, the gathering and processing costs for the 49 plants far exceed liqiud revenues; and the Examiner so finds.

Producer Witness' Adjustments of Staff Rate-Design Exhibit

As already noted, staff witness Engel's rate design, Exhibit 60, utilizes certain of the plant costs developed by Bateman. In his rebuttal to Engel, producer witness Carney excepts only to Engel's use of two of the group of plants in Pricing Area 2—Sunray, South Sarepta; and Tidewater, New Hope. The Examiner agrees with Carney that Exhibit 60 should be adjusted by the eliminiation of these plants. In the test year, there were no sales from either of the plants. (50:5303; Ex. 88, Sch. 8.)

Next, Carney makes certain adjustments to throughput

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(especially volumes compressed) in Pricing Areas 2 and 1. The basis for these adjustments is set out in Exhibit 88, Schedule 1. (50:5305.) The staff do not question these adjustments. The Examiner accepts them.

Lastly, Carney would adjust Engel's calculations to correct for a claimed so-called "big divisor" error. The error, according to the producer witness, consists in Engel's using total gas output of the plants as a divisor in determining average unit processing costs, rather than using average throughput weighted by functional costs. (50: 5299-5301.) The claim of error is without merit.

Carney's adjustment is incorrect because the adjusted unit cost which he develops on an average throughput

basis is inconsistent with the sales volumes to which such unit cost would be applied. Engel applies his average processing cost to total jurisdictional sales of processed gas-well gas (not to some artificial weighted average sales throughput), and therefore his unit processing cost and the volumes to which it is applied are on a compatible basis. The calculations in Appendix D hereto demonstrate the correctness of Engel's result.

IX. RATE DESIGN

In each of the three pricing areas, Engel recommends the establishment of separate rate ceilings for (1) new gas-well gas (and residue gas derived therefrom); and (2) all other gas, sometimes referred to as "flowing gas" (old gas-well gas and all casinghead gas, and residue gas derived from either). (20:2674, 2694.) The ceiling prices (or base area rates) would be applicable to jursidictional sales of "pipeline quality gas" to pipelines or intermediate buyers, with specific deductions for gas not meeting quality standards. (20:2674, 2694.)

The ceiling rates proposed by Engel are as follows (at 14.65 psia, except north Louisiana, Mississippi and northwest Alabama rates at 15.025 psia), for pipeline quality gas:

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Pricing Area	Ceiling Rates	
	New Gas (¢/Mcf)	Flowing Gas (¢/Mcf)
(1) Other Oklahoma	17.50	17.00
Texas RRD No. 9	17.75	17.25
North Arkansas	17.00	16.50
(2) Texas RRD Nos. 5 and 6	17.50	14.00
North Louisiana	19.00	15.75
South Arkansas	16.75	13.50
(3) Mississippi and Northwest Alabama	18.00	16.50

(Ex. 60, Sch. 1)

The Examiner approves the rate-design approach followed by Engel and employs such approach herein, with those adjustments necessary in light of the findings made herein.

Derivation of Ceiling Rates for Flowing Gas

Finding and Producing Costs. Engel has reconstituted the gas-well gas production costs developed by staff witness Murr to conform to the three pricing areas. The Examiner has accepted Murr's costing *in toto* (*supra*, p. 85), and he finds as well that the reconstituted costs are reasonable and justified. The reconstituted costs are: for Pricing Area 1, 10.11¢; for Pricing Area 2, 7.45¢; and for Pricing Area 3, 9.57¢. (Ex. 60, Sch. 3, sheet 8.) Adding the allowances for E&D expense of 4.01¢ and regulatory expense of 0.17¢ (*supra*, p. 89) results in total finding and producing unit costs applicable to gas-well gas sales to pipelines of 14.29¢, 11.63¢ and 13.75¢, respectively. These costs are listed in Appendix F hereto, which sets out the items constituting the unit cost of pipeline quality flowing gas-well gas in the respective areas.

Cost of Processing Incurred Beyond the Lease. To the finding and producing costs determined above, there must be added the producer-incurred cost of plant processing of gas-well gas beyond the lease. It has been noted that for his rate-design purposes, Engel selected from Bateman's study those plants which handle mainly gas-well gas. (*Supra*, p. 115.) All such plants are located in Pricing Areas 1 and 2. (Ex. 60, Sch. 3, sheet 7.) For Pricing Area 3, Engel employed all plants shown by Bateman, three in number. (Ex. 60, Sch. 3, sheet 6; Ex. 59, Sch. 1, sheet 2.)

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The issue respecting the proper method of allocating joint plant cost has been resolved by adoption of the 1:1

Btu method. (*Supra*, pp. 111-112.) This issue has substance only in relation to Pricing Areas 1 and 2. In Area 3, there is only an insignificant amount of residue gas-well gas sold to pipelines, virtually all of the gas processed being oil-well gas. Under any allocation method, the processing costs are *de minimis* in the rate-design calculations for this area. (Ex. 60, Sch. 3, sheets 3, 5; 20:2686.)

It has been found that Engel's plant costs calculations should be adjusted to include a specific cost allowance for fuel used in gas compression, treating, and dehydration; and that this allowance is calculated at 20% of the other applicable functional costs. (*Supra*, p. 112.) Certain minor corrections to plant throughput volumes, advanced by Carney, have been accepted. (*Supra*, pp. 115-16.) Finally, it has been found appropriate to exclude the South Sarepta and New Hope plants from Engel's Area 2 plant group. (*Supra*, p. 115.)

Engel's plant cost calculations for Pricing Areas 1 and 2 have been adjusted to reflect these findings. No adjustment is required for Areas 3 because of the insignificance of gas-well gas processing in that area. The adjusted processing cost per Mcf of residue delivered is calculated at 2.71¢ for Area 1 and 1.53¢ for Area 2. Substituting these unit costs for those shown by Engel and averaging the resulting processing costs over total gas-well gas sales to pipelines yields 0.81¢ per Mcf in Area 1 (excluding plant gathering) and 0.80¢ in Area 2. The Area 2 increment includes 0.34¢ for plant gatherings and 0.46¢ for other plant functions. These figures are reflected in Appendix E hereto, staff's plant costs for Pricing Areas 1 and 2, revised.

Producer-Operated Separate Gathering Systems. Only in Pricing Area 2 are there significant jurisdictional gas-well gas deliveries to pipelines through producer-operated

separate gathering systems. (Ex. 60, Sch. 6.) As will be discussed *infra*, Area 2 requires different treatment from Areas 1 and 3 respecting gathering. In Area 2, Engel rolled in the costs of these separate systems, thus increasing average producer-incurred costs per Mcf of sales by 0.80¢, as shown in Appendix F.

Pipeline-Incurred Conditioning Costs. In bringing gas up to pipeline quality, pipeline purchasers in the Other Southwest Area incur costs for sweetening, dehydration, compression, and removal of carbon dioxide. The conditioning costs employed by Engel to measure such quality improvement are at the same unit level as his recommended specific quality deductions set out

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supra, at page 109. While it has been found that the amount of price deduction for low-quality gas on an individual contract basis should be left to the parties to negotiate, Engel's recommended unit conditionag costs are nevertheless appropriate for use in measuring the average cost of conditioning total volumes of gas requiring quality improvement.

There is an issue respecting the volumes to which a charge for dehydration should apply. The pipelines purchased large volumes of unprocessed gas for which they did not report any dehydration costs on the ACD. In Pricing Area 3, for example, according to the ACD, pipelines purchased over 73 million Mcf of unprocessed gas and incurred dehydration costs for about 20 million Mcf. Engel reflects only the 20 million Mcf as requiring dehydration by the pipeline purchasers. (Ex. 60, Sch. 3, sheet 3.) Yet he states, as does Carney that all gas is produced wet and must be dehydrated. (41:4388, 50: 5442.) The record does not permit a finding as to the

reason for this apparent discrepancy. However, the cause is immaterial. Reegardless of the reason for the discrepancy, it is appropriate to treat all unprocessed gas as requiring dehydration inasmuch as the rates here prescribed require either the delivery of dry gas, or quality deduction from ceiling rates for delivery of wet gas.

Therefore, an adjustment of Engel's calculations is required to reflect dehydration by the pipelines of all unprocessed gas-well gas purchased by them. This adjustment results in total pipeline-incurred conditioning costs, on a rolled-in basis, of 0.50¢ per Mcf in Area 1, 0.27¢ in Area 2, and 0.43¢ in Area 3, as shown in Appendix F.

Gathering Allowance. Engel recomends gathering allowance of 1.25¢ per Mcf in Pricing Areas 1 and 3, and 1.00¢ per Mcf in Pricing Area 2. (Ex. 60, Sch. 1.) His determination of the reasonableness of the charges "involved review of the contract provisions, the actual deductive or additive charges, plus the fuctional costs within plants." (43:4515.)

In making his rate-design calculations for Areas 1 and 3, Engel added "a flat unit gathering allowance" to the total of producer-incurred finding and producing costs and processing costs, and pipeline-incurred conditioning costs. But this procedure was not followed in Area 2, "where substantial gathering costs are imbedded in the lease and/or plant costs and the remainder of the gas requiring gathering is costed as pipeline incurred." (20: 2680.)

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In Area 1, where the bulk of the gas-well gas sold to pipelines is delivered at the wellhead, the recommended 1.25¢ gathering allowance "is about equal to the unit gathering costs allocated [on a 2:1 Btu basis] to residue gas sales. . . ."

Respecting Area 2, Engel states:

> "About 65% of the gas well gas sold to pipelines is gathered by producers through lease or field lines or gathering system attached to processing plants. It follows that the remaining 35% of the gas requires gathering by the pipeline. Since I am unable to separate the substantial gathering costs from the lease production costs, I have rolled the gathering costs with the lease costs. . . ." (20:2684.)

The 1.0¢ per Mcf for pipeline-incurred gathering is estimated from analysis of allocated plant gathering cost and review of applicable contract charges. (20:2684-85; Ex. 60, Sch. 3, sheet 4.)

Engel believes that Area 3 requires treatment similar to Area 1 respecting gathering, but takes into consideration the fact that about one-third of the gas in Area 3 has gathering costs imbedded in the lease costs which cannot be segregated. (20:2685; 41:4382.) In concluding that 1.25¢ gathering allowance (at 15.025 psia) is reasonable, he is aware that the allocated plant gathering cost on a 2:1 Btu basis is about 1.8¢; but he notes that such costs covers only about 11 million Mcf of oil-well gas. (20:2686.)

In order to qualify for the recommended ceiling prices including the gathering allowance, Engel would require the seller to perform "substantial" gathering, regardless of point of delivery. (20:2690; 41:4386-87; 43:4518, 4607.)

Engel's recommended gathering allowances in Areas 1 and 2 must be evaluated in light of the finding that plants costs in those areas should be allocated on a 1:1 Btu basis. This evaluation leads to the conclusion that the allowance for Area 1 should be 1.50¢ rather than 1.25¢. The allocated plant gathering cost in such area is 1.49¢ with a 1:1 Btu allocation, rather than 1.26¢ shown by Engel. No modification of the 1.0¢ allowance recom-

mended by Engel in Area 2 is warranted since the allocated gathering cost with either a 1:1 or 2:1 Btu allocation is less than the recommended allowance. (43:4516-17; App. E hereto.) Rolling in the cost at 1.0¢ per Mcf on the volumes considered to be pipeline gathered in Area 2 results in an increment of 0.35¢ per Mcf of total gas-well gas sales.

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The allowances thus adopted by the Examiner are shown on Appendix F.

Production Taxes. In calculating local production taxes for jurisdictions where the tax is a percentage of wellhead valuation, it is appropriate to exclude from the tax base, as Engel has done, any gathering costs or allowances to the extent that such costs are separately identifiable. (35:3920-21.) However, Engel would exclude from the tax base all "beyond-the-lease" costs. (Ex. 60, Sch. 3, sheet 9.) The Examiner does not agree that such costs should be excluded from the calculation. Since ceiling rates are here being determined for pipeline quality gas, and such rates have been developed by rolling in the costs, wherever incurred, of bringing gas up to pipeline quality, it is necessary to include in the tax base all quality improvement costs. Only in this manner will the calculation yield the appropriate tax on pipeline quality gas.

The state tax rates employed by Engel are not controverted and will be used herein. They are, as shown in Appendix F: Oklahoma, 5% + 0.04¢ per Mcf; Texas, 7%; Arkansas, 0.35¢ per Mcf; Louisiana, 2.3¢ per Mcf (15:025 psia); Mississippi and Alabama, 6%.

Total Costs and Ceiling Rates for Pipeline Quality Flowing Gas. The following total costs, as shown in Ap-

pendix F, and ceiling rates for pipeline quality gathered gas are hereby determined and adopted:

	Total Cost	Ceiling Rate
Pricing Area 1	¢/Mcf	¢/Mcf
Other Oklahoma	17.49	17.5
Texas RRD No. 9	17.79	17.8
Northern Arkansas	17.00	17.0
Pricing Area 2		
Texas RRD Nos. 5 and 6	14.06	14.1
Northern Louisiana[a]	15.77	15.8
Southern Arkansas	13.48	13.5
Pricing Area 3		
Mississippi (onshore) and Alabama[a]	16.72	16.75

[a]Costs and rates for Northern Louisiana, Mississippi (onshore) and Alabama are shown at 15.025 psia. All others at 14.65 psia.

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Where the seller does not perform substantial gathering, the applicable ceiling rates are 1.5¢ less in Area 1, 1.0¢ less in Area 2, and 1.25¢ less in Area 3.

Derivation of Ceiling Rates for New Gas-Well Gas

The nationwide cost of new gas-well gas determined herein is 16.22¢ per Mcf, including *inter alia* a 10 ½% rate of return, a 14% royalty, and an illustrative 7% nationwide production tax. (*Supra*, p. 72..) Such cost is essentially a wellhead cost (20:2693), and applies to gas of average quality.

As a starting point in the design of rates for new gas-well gas, Engel uses a nationwide new-gas costing at a 12% rate of return. He permits an additional gathering allowance for deliveries involving substantial gathering

by the seller. However, he does not include specific allowances covering the cost of bringing new gas up to pipeline quality, since he accepts the new-gas costing at a 12% rate of return "as an adequate level of cost to compensate for the risk of finding gas of a quality which may not meet [his]recommended standards." (20:2693.)

In the Examiner's derivation of ceiling rates for new gas-well gas, it is appropriate to add specific area quality improvements costs; since the 10 ½% rate of return does not include or give effect to the risk of finding low-quality gas. The quality improvement costs hereinafter included are the same as those reflected in the rate design for flowing gas, except as to the cost of plant fuel. No specific allowance is made for the plant-fuel cost because the new gas-well gas costing already reflects such allowance in the liquid-credit calculation. (*Supra*, p. 66.) It is also appropriate to adopt the same gathering allowances for new gas-well gas as have been found proper for flowing gas. (20:2693.) Royalty and percentage production taxes are calculated on a tax base which includes all costs exclusive of separately identifiable gathering charges. (See Appendix G.) The nationwide new gas-well gas cost which has been hereinbefore found, exclusive of royalty and production tax, is 12.97¢ per Mcf at 14.65 psia. (*Supra*, p. 72.)

The Examiner finds and concludes that the total cost of pipeline quality gathered new gas-well gas, including royalty at 14% and applicable state production tax, and ceiling rates applicable thereto, are as follows:

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	Total Cost ¢/Mcf	Ceiling Rate ¢/Mcf
Pricing Area 1		
Other Oklahoma	18.32	18.4
Texas RRD No. 9	18.64	18.7
Northern Arkansas	17.79	17.8
Pricing Area 2		
Texas RRD Nos. 5 and 6	18.05	18.1
Northern Louisiana[a]	19.57	19.6
Southern Arkansas	17.21	17.25
Pricing Area 3		
Mississippi (onshore) and Alabama[a]	18.25	18.25

[a]Costs and rates for Northern Louisiana, Mississippi (onshore) and Alabama are shown at 15.025 psia. All others at 14.65 psia.

In cases where the seller does not perform substantial gathering, the applicable ceiling rates are less by 1.5¢ per Mcf in Area 1, 1.0¢ per Mcf in Area 2, and 1.25¢ per Mcf in Area 3.

X. MISCELLANEOUS MATTERS

Question of Minimum Rates

The staff recommend that minimum rates be fixed, ranging from 10.00¢ to to 12.75¢ per Mcf. (Staff Br., 190-91.) TIPRO recommends an area-wide minimum rate of 13.50¢, with a 1¢ escalation each five years until the minimum reaches the level of the ceiling rate. The producer group make no recommendation respecting minimum rates. (49: 5249.) The pipeline purchaser group oppose adoption of minimum rates.

The applicable criteria are set out in *Permian Cases*, 390 U.S., at 820:

"This Court has held, under the Federal Power Act, that the Commission may not abrogate existing contractual arrangements unless the contract price is so 'low as to adversely affect the public interest—as where it might impair the financial ability of the public utility to

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continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory.' *Federal Power Commission* v. *Sierra Pacific Power Co.*, [350 U.S.], at 355. It is not enough, the Court there held, that the contract price permits less than a fair return; the Commission may not, absent evidence of injury to the public interest, relieve a regulated company of 'its improvident bargain.' *Ibid.* The pertinent provisions of the Federal Power Act 'are in all material respects substantially identical to the equivalent provisions of the Natural Gas Act.' *Id.*, at 353. It follows that the Commission was here without authority to abrogate existing contract prices unless it first concluded that they 'adversely affect the public interest.'"

And at page 822:

"The regulatory system created by the Act is premised on contractual agreements voluntarily devised by the regulated companies; it contemplates abrogation of these agreements only in circumstances of unequivocal public necessity."

There is no showing that there are any contract prices in the Other Southwest Area which are so low as adversely to affect the public interest. There is a dearth of evidence that any producers need "relief from prices so low as to seriously impair [their] ability to compete for the acquisition of leases or to otherwise participate in the necessary exploration in search of new reserves due to a

lack of revenue generated from current production." (*Southern Louisiana*, Opinion 546, mimeo., at 112.) On the contrary, the record reveals that the staff-suggested minimum rates would have an insignificant impact on both producers and consumers. (20:2695.) The pipeline group assert that "in the absence of evidence showing a cognizable effect resulting from a minimum price, or that the funds generated therefrom would have a bearing on future exploration, the record does not support the required finding that existing contract prices are 'so low as to adversely affect the public interest.'" (Pipeline Br., 17.) The Examiner agrees.

Moreover, in the Examiner's opinion it is in the public interest not to prescribe minimum rates. The Examiner agrees with the pipeline group that "individual contracts, which take into account the significant economic considerations of each sale, far better serve the consumer market than any price floor." (Pipeline Br., 16.) Both the minimum prices recommended by the staff and those recommended by TIPRO would tend to discourage the future acquisition of poorly located or otherwise unattractive gas reserves, and thereby preclude these supplies of gas from the

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interstate market. The Examiner takes official notice of this fact, as a matter "as to which the Commission by reason of its functions is an expert." (*Rules of Practice and Procedure*, Sec. 126(d).)

The staff aver that their recommended minimum rates "represent a reasonable balancing of producer and consumer equities." (Staff Br., 191.) This averment is beside the point and immaterial under the criteria of the *Permian Cases.*

Presiding Examiner's Initial Decision

The Examiner rejects the recommendations of the staff and TIPRO, and further concludes that no minimum rates should be fixed.

Small Producer Exemptions

A small producer is defined to be a natural-gas company having jurisdictional sales not in excess of 10,000,000 Mcf annually on a nationwide basis. The combined jurisdictional sales of affiliated companies are to be considered as the sales of a single producer.

In *Southern Louisiana*, Opinion 546, mimeo. 95, referring to *Permian*, the Commission stated, ". . . special relief is appropriate for the smaller, independent producer in the matter of certificate and rate filings . . . ." The Examiner so concludes respecting the respondent small independent producers, and extends to them the same relief which the Commission accorded the small producers in *Permian* and *Southern Louisiana*.

Companies or individuals in the Other Southwest Area qualifying as small producers will be granted small producer certificates of public convenience and necessity, pursuant to Section 7 of the Act, authorizing all future small producer sales in the area at or below the applicable area ceiling rate, thereby eliminating the need to obtain separate certificates for each sale.

Order No. 308, 34 F.P.C. 1202, issued October 29, 1965, amended the *Regulations under the Natural Gas Act* by adding Section 157.40, granting relief from the normal certificate and rate filing requirements to small producers operating in the Permian Basin Area. The amendment provided for the issuance of small producer certificates authorizing sales in that area at prices no higher than the area ceilings. The Commission declined at that time and earlier in *Permian* to extend the same coverage to

pricing areas outside the Permian Basin on the ground that a specific area rate was a prerequisite for the issuance of the small producer certificate. By order amending Section 157.40, issued September 25, 1968, in *Southern Louisiana*, Opinion 546,

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at 95-96, 148, the Commission extended this coverage, under the same terms, to the small producers operating in Southern Louisiana. The Examiner recommends that the Commission further amend Section 157.40 of the *Regulations* by adding provisions extending the same coverage to small producers operating in the Other Southwest Area respecting their small producer sales in such area.

In *Permian* and *Southern Louisiana*, the Commission exempted small producers from the quality deficiency adjustment and Btu adjustment requirements. This was done on the *de minimis* principle, since it was concluded that the burden and expense involved would in most cases exceed the amount of the adjustment. The Examiner accords like exemptions to the respondent small producers. In these circumstances, it is appropriate to allow the small producer to claim any upward Btu adjustment, to which he may be entitled under this decision, with respect to any filings covered by his small producer certificate. The Examiner so prescribes. This action will permit a small producer to secure the benefits of an upward Btu adjustment without his having to file separately those rate schedules under which the adjustment is claimed. However, any small producer claiming an upward Btu adjustment with respect to a particular sale will be subject for that sale to the quality adjustments herein specified.

The Examiner incorporates by reference the last para-

graph on mimeo. page 96 of *Southern Louisiana*, Opinion 546, except that "Southern Louisiana" on the first line of such paragraph, and "Southern Louisiana" on the fifth line from the bottom of the page, are changed to "Other Southwest Area." The Examiner also incorporates by reference the first paragraph on mimeo. page 97 of *Southern Louisiana*, Opinion 546.

Any producer operating both in the Other Southwest Area and in either the Permian Basin or Southern Louisiana Areas, and who has been granted a small producer certificate under *Permian*, Opinion 468, or *Southern Louisiana*, Opinion 546, will have his certificate extended on application to cover his Other Southwest Area sales. The annual report thereafter filed by such producer should include a certification that the rates charged by him comply both with Opinion 468, or Opinion 546, and this decision.

The Examiner incorporates by reference the last paragraph on mimeo. page 97 of *Southern Louisiana*, Opinion 546, except that "Opinion" on the third line of such paragraph is changed to "decision," and "this Opinion" on the fifth line of such paragraph is changed to "the Commission's opinion herein." The Examiner incorporates by reference the paragraph on mimeo. page 98 of *Southern Louisiana*, Opinion 546.

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Moratorium

Upon the authority of *Southern Louisiana*, Opinion 546, mimeo., at 136-39, the rates herein established for "flowing gas," as defined *supra*, page 116, should be continued until such time as they may be changed by the Commission. The risk of serious cost increase "is least significant in the case of the older contracts where most costs were sunk long ago . . . ."

In *Southern Louisiana, supra,* the Commission also adopted an indefinite moratorium for "second-vintage" gas-well gas; *i.e.*, gas-well gas sold and to be sold pursuant to contracts dated on or after January 1, 1961, but prior to October 1, 1968, and any residue gas derived therefrom. In so prescribing, the Commission took into consideration that it was allowing ceiling rates for such contracts, "significantly above the computed cost per Mcf." (*Ibid.*, at 137.) In this respect, the situation here differs from that in *Southern Louisiana.* In the Other Southwest Area, as in the Permian Basin Area, "there is no justification . . . for any adjustment of a cost-determined ceiling price." *Permian,* 34 F.P.C., at 207.[36]

Since the reason in *Southern Louisiana* quoted above for granting an indefinite moratorium for second-vintage gas is not the case in the instant proceeding, an indefinite moratorium is unwarranted by that opinion except as to "flowing gas." For gas-well gas sold and to be sold pursuant to contracts dated on or after January 1, 1961, and any residue gas derived therefrom, the Examiner will

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[36] The Supreme Court in *Permian Cases,* 390 U.S., at 815, note 98, observed that the Commission employed four noncost factors; *viz.*,

> "It used the logic of functional pricing to justify both its two-price rate structure and its selections of sources of cost data. Second, it explained its imposition of a single maximum rate upon all old gas by, among other reasons, the importance of a relatively uncomplicated rate structure. Third, the Commission justified its adoption of a temporary period of price restriction by the exigencies of area regulation. Fourth, the Commission based its calculation of the rate of return upon risk factors that it did not directly reduce to cost components."

These four factors are not specifically measurable departures from cost, and only the first two apply in the instant proceeding. Obviously, these two noncost factors do not justify prescribing an indefinite moratorium within the rule of *Southern Louisiana.*

fix a moratorium expiring five years after the date of the Commission's order herein.

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Cut-Off Date

Following Commission precedent, the Examiner fixes January 1, 1961, as the cut-off date between new gas-well gas and old gas-well gas; and prescribes that the new gas-well gas price shall apply to gas-well gas sold and to be sold pursuant to contracts dated on or after January 1, 1961, and any residue gas derived therefrom. (*Southern Louisiana*, Opinion 546, mimeo., at 20; Opinion 546-A, mimeo., at 6-7.) Arguments of AGD and the producer group advocating different dates are responded to in *Southern Louisiana* at the cited pages.

The producer group contend that new casinghead gas should be accorded the new gas ceiling. (Prod. Br., 278-80.) The Examiner rejects this argument on the authority of *Southern Louisiana*, Opinion 546, mimeo., at 64-65, 130-31; Opinion 546-A, mimeo., at 13.

Quality Adjustment Procedure

The producer respondents will be required to file a form similar to Appendix G of *Southern Louisiana*, Opinion 546, as modified to be applicable to this proceeding and to reflect the findings made herein. It should be noted that while delivery point has not been treated as a "quality feature," separate ceiling rates have been fixed for different delivery conditions.

Small producers filing under a small producer certificate will not be required to submit a quality statement or be subject to quality adjustments. However, any small producer claiming an upward Btu adjustment respecting a particular sale will be subject for that sale to all qual-

ity adjustments. See *Southern Louisiana*, Opinion 546, mimeo., at 96; *Permian*, 34 F.P.C., at 233.

Intermediate Sales

The staff recommend that the ceiling prices applicable to sales by a producer to a pipeline purchaser also be made applicable to sales by a producer to intermediate purchasers; and, as in the case of sales to pipelines, be subject to quality price adjustments. If such deductions are not sufficient to cover any improvement and gathering costs of the intermediate purchaser,

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the staff would have the producer and intermediate purchaser renegotiate their contract so as to provide a reasonable differential between the price paid by the intermediate purchaser and that received by him from the pipeline purchaser. Should the producer and intermediate purchaser be unable to reach agreement, the staff would have the price determined by the Commission, presumably on application of the intermediate purchaser for special relief. (Staff Br., 192.) This recommendation is unopposed. The Examiner will so prescribe.

Prepayments

The Examiner prescribes that, as to prepayments made by pipelines to producers under contracts requiring gas to be paid for even though delivery has been deferred, the governing rate is the rate applicable at the time of prepayment obligation rather than the rate applicable at the time the make-up gas is actually delivered. Producers selling gas at rates not subject to refund, under

contracts containing prepayment provisions in which deliveries are deferred, have no obligation to refund the difference between the area rates and the rate in effect and actually charged the buyer at the time the prepayments are made. No adjustment in future deliveries of gas for which payment has been made under prepayment provisions will be required to reflect the difference between the area rates and the rate in effect and actually charged the buyer at the time the prepayments are made.

Order No. 334, 37 F.P.C. 110, provides for a minimum five-year make-up period in such contracts. By the terms of the order, the rule therein prescribed is applicable to gas contracts executed after February 1, 1967; and makes subject to the rule, producer certificates previously conditioned by being made subject to the final outcome of Docket No. R-199. Any sales subject to the application of the order in this proceeding having such condition in the initial certificate of public convenience and necessity are bound by Order No. 334 and the requirements thereof. See *Southern Louisiana*, Opinion 546, mimeo., 118.

Indefinite Escalation Provisions

Section 154.93 of the *Regulations under the Natural Gas Act*, as amended by order issued February 8, 1962 (27 F.P.C. 339), prohibits the filing of contracts executed on or after April 2, 1962, which contain indefinite pricing provisions, except for certain specified permissible provisions. Indefinite price escalation clauses in contracts already accepted for filing at the time of the order of February 8, 1962, and which have not otherwise been held inoperative, will not be permitted effect to the extent of providing contractual authorization for rate

increase filings beyond the applicable area rates. This prohibition applies both during the moratorium period provided for herein and, in the case of new gas-well gas, subsequent to the expiration of such period. *Southern Louisiana*, Opinion 546, 109; *Permian*, 34 F.P.C., at 236-37.

Refunds

The Examiner incorporates by reference mimeo. pages 115, 116, and the first six lines of mimeo. page 117 of *Southern Louisiana*, Opinion 546.

In *Federal Power Commission* v. *Sunray DX Oil Co.*, 391 U.S. 9, 24, the Supreme Court held that an initial price which is authorized in a final, unconditioned permanent certificate is a lower limit below which a refund cannot be ordered under Section 4(e). In view of this decision, no producer will be required to make refunds in a Section 4(e) proceeding below the rate allowed by final order no longer subject to judicial review permanently certificating the sale in question and containing no refund condition. (*Southern Louisiana*, Opinion 546, mimeo., 117; Opinion 546-A, mimeo., 34, 48.)

In accordance with Section 154.102(f) of the *Regulations under the Natual Gas Act*, no interest should be required on refundable amounts paid over to the federal and state governments in royalties, except as and to the extent that such authorities pay interest to the producer when refunding overpayments of royalties. (*Ibid.*, Opinion 546-A, mimeo., 36.)

Special Relief Procedure

The producer group contend that a savings clause in the final order in this proceeding should (1) provide a

stay of the rate order to any producer pending a hearing on his application for relief, (2) state with clarity the evidentiary showing required, and (3) define the relief to be afforded if the required evidentiary showing is satisfied. (Prod. Br., 284-85.) The Examiner rejects these contentions. As reason for doing so, he incorporates by reference mimeo. pages 99 to 104, inclusive, of *Southern Louisiana*, Opinion 546.

Application of Order

The producer group contend that the final order in this proceeding can reach, (1) under Section 5 of the Act, only those jurisdictional sales being made on February 28, 1967, the date of institution of this proceeding; and, (2) under Section 4 of the Act, only those rate increase proceedings filed on or before such date and consolidated with the area rate proceeding. The

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producer group further contend that the final order in this proceeding "cannot control the disposition of future applications for certificates of public convenience and necessity under Section 7 of the Act." Prod. Br., 283-84.)

These arguments are without merit. This proceeding was instituted as a rulemaking proceeding as well as one to adjudicate particular Section 4(e) and Section 5(a) cases. Of the matters and proceedings referred to by the producers, the only ones that will not be reached by the Commission's final order herein are the refund obligations under unconsolidated Section 4(e) proceedings. More specifically in response to the producers' contentions, the Examiner incorporates by reference the following portions of *Southern Louisiana*, Opinion 546, as hereby modified: (1) The first paragraph on mimeo. page 110, with

these changes: line 1 of such paragraph, change "The Examiner followed" to "Following"; lines 1 and 2 of such paragraph, delete "in providing that"; line 3 of such paragraph, delete "would." (2) The second paragraph on mimeo. page 110. (3) The third paragraph on mimeo. page 110, with these changes: line 1 of such paragraph, delete, "As observed by the Examiner," and change "the" to "The"; line 2 of such paragraph, delete "(25 F.P.C. at p. 944)"; line 4 of such paragraph, change "Southern Louisiana" to "the Other Southwest Area." (4) The last paragraph on mimeo. page 110. As a continuation of such paragraph, insert the following: "It is to be understood, however, that this decision does not automatically resolve all certificate issues, including the appropriate refunds for past periods of operation under temporary certificates. (Opinion 546-A, at mimeo. p. 36.)" (5) The first paragraph on mimeo. page 111 of Opinion 546. (6) The last three lines on mimeo. page 139 of Opinion 546. (7) The portion of mimeo. page 140 of Opinion 546 commencing at the top of the page and continuing to the paragraph lettered (k).

New Gas-Well Gas on Previously Committed Acreage

By order issued February 4, 1969 in *Hugoton-Anadarko*, Docket No. AR64-1, the Commission severed from the other issues in that proceeding, for separate decision, the question of how, pricewise, the new production on already-committed acreage should be treated. The same issue is presented in this case.

The order in Docket No. AR64-1 recites that in view of the importance of such issue to the parties in other area rate proceedings, and the comparatively narrow scope of the issue, no purpose would be served by delaying its resolution until the other issues in the proceeding

are resolved. The order indicates that any change in policy as a result of the decision of

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such question in *Hugoton-Anadarko* will be applied prospectively in *Permian*. In *Southern Louisiana*, Opinion 546, at mimeo. page 123, the Commission said, "The decision dealing with the proper price for new production on committed acreage has been deferred . . . for resolution in the Docket No. AR64-1 proceeding where a record on this subject has been compiled." On rehearing, the Commission further said, "Any change in policy, we have stated, will be applied prospectively in both the Permian Basin area and the Southern Louisiana area. (Opinion 546-A, mimeo., 11-12.) In this proceeding, likewise, the Examiner defers a decision on the question for resolution in Docket No. AR64-1.

Claim of Built-in Revenue Deficiency

The producer group contend that there is a bulit-in revenue deficiency in the staff aproach to rate design for the reason that the ceiling prices are fixed at the level of average cost. To the extent that there are sales at contract prices below the ceilings, they argue, the average revenue which will be realized inevitably must be lower than the ceilings and therefore lower than cost. (Prod. Br., 256.) They conclude that the Commission is required to balance revenue and costs, preferably by setting the ceiling price above the level of average cost. (Prod. Br., 258.) The Supreme Court has already passed on this question adversely to the position of the producer group. *Permian Cases*, 390 U.S., at 818-22.

At page 819 of the decision, the Supreme Court makes use of the following language, equally applicable here:

". . . the Commission's computation of its area rates was not intended to reflect with complete fidelity either the producers' average costs or their sources of revenue. . . . the actual average unit costs of casinghead and residue gas are substantially lower than the average unit costs of flowing gas-well gas; yet the maximum rate for all associated and flowing gas was derived entirely from the latter. It follows that the producers' net revenues from sales of casinghead and residue gas will prove higher than the return formally permitted by the Commission."

The following observations in *Southern Louisiana*, Opinion 546, are pertinent: "In *Permian*, . . . we recognized that it would be unrealistic to assign large exploration expenditures to casinghead gas since this gas is found largely as a by-product in the search for oil." (Mimeo., 21.) "We adhere to the conclusion that oil-well gas is, in many respects, a by-product of crude oil and economically has a lower cost than gas-well gas (34 FPC 190, 211), and we give that conclusion some weight in assessing the total impact of the rate levels we fix." (Mimeo., 130-31.)

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In *Southern Louisiana* only about 17% of the gas produced was casinghead (mimeo., 24), whereas in the Other Southwest Area, the proportion of casinghead gas is from 27% to 30%. (Prod. Br., 262.) Hence, the impact of the low cost of casinghead gas upon the producers' net revenues is greater here than in *Southern Louisiana*. Furthermore, casinghead gas has been recognized as performing a lifting service for the oil, and it can be forcefully argued that this service justifies a cost credit for the gas. See *Phillips Petroleum Company*,

24 F.P.C., at 555; *Ibid.* (Examiner's initial decision), at 631-33.

Also to be taken into account, as a counterbalancing factor to the producers' claim of cost-revenue deficiency, is the administrative generosity herein which is accorded producers in back-dating the new-gas incentive price to January 1, 1961. (*Supra*, p. 128.) Note in this connection the comments of the Supreme Court in justifying the Commission's similar generosity in *Permian. Permian Cases*, 390 U.S., at 798-99.

Evidence presented by producer witness Gody purports to show that in certain parts of the Other Southwest Area, substantial increases in producers' average revenue realization—enough to equal or exceed the average cost of gas-well gas—can be achieved by raising ceiling prices; but that in other parts of the hearing area, no such cost-revenue balance would result no matter what ceiling prices were established. (Ex. 91; 50: 5364, 5369.) Producers urge that the ceiling prices be raised sufficiently in the sectors where substantial increases in average revenue realization can be achieved, in order to offset the claimed cost-revenue deficiences in those other areas. (Prod. Br., 258-61.) In response, first, as has been shown, the average unit cost of gas-well gas determined herein is not the measure of producers' area "revenue requirement"; rather it establishes the level of ceiling rates. Second, adoption of the producer recommendation would result in serious ceiling-price departure from gas-well gas costs within the pricing areas herein precribed; and would, to that extent, defeat the purpose of establishing the pricing area. Finally, the discussion at pages 820-22 of *Permian Cases* is applicable to the instant case. The record shows no necessity or justification for making adjustments in the area rates because of prevailing contract prices; and on the con-

trary, indicates that such adjustments are unjustified. Here, as in *Permian Cases*, "such adjustments would increase the cost of natural gas to some groups of consumers, in order simply to offset bargains previously obtained by others." The Examiner rejects the contention of the producer group.

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Question of Competition in Gas Industry

Based on Foster's testimony, the producer group contend that existing prices in the Other Southwest are insufficient to elicit the needed supplies. (Prod. Br., 234.) However, they argue that claimed effective competition in the natural-gas producing industry warrants acceptance of contract prices as an "important guidepost" to define the standards for area prices (Prod. Br., 33, 34.)

The staff and AGD oppose the claim that there is effective competition in the natural-gas industry. The position of the staff and AGD is supported by *Permian* and *Southern Louisiana.* (See *Southern Louisiana*, Opinion 546, mimeo., 16.)

No witness testified upon the question of competition in the instant proceeding. However, some evidence on this matter was incorporated by reference from the joint record and from separate records in *Hugoton-Anadarko* and *Texas Gulf Coast.* Such evidence consists of testimony of Dr. James W. McKie, an economist, and exhibits sponsored by him, on behalf of the producer group; and tesimony of Dr. Samuel Blitman, a staff economist in rebuttal.

Respecting this incorporated evidence, the Examiner incorporates by reference portions of the initial decisions in *Hugoton-Anadarko* and *Texas Gulf Cost; viz.*, that portion of the *Hugoton-Anadarko* initial decision begin-

ning with the second sentence on mimeo. page 29, to and including mimeo. page 36; that portion of the *Texas Gulf Coast* initial decision beginning with "Producers" on the sixth line from the bottom of mimeo. page 31 to and including the third line on mimeo. page 35. The excerpt from the *Texas Gulf Coast* decision, as well as that from the *Hugoton-Anadarko* decision, expresses the independent judgment of this Examiner; and he adopts it as his own.

The Examiner concludes that in the Other Southwest Area, as in the Hugoton-Anadarko and Texas Gulf Coast Areas, competition is ineffective and inadequate to assure consumers just and reasonable rates.

Noncost Factors

Rate Proposals of Producers and AGD. The rates proposed by producer witness Foster are set out in the last column of the tabluation *supra*, at page 26, with still higher rates being required (at unstated levels) if a system of mandatory delivery conditions be adopted. (*Supra*, p. 25.)

Foster's rates are predicated on noncost factors, the primary determinants being contract price history, the higher range of regulated prices in the area, and a claimed need for

additional incentives to elicit new supplies for the interstate market.

It is true that the witness says that he looks to cost estimates "as a point of departure." (20:2571-72.) The estimates are from the cost studies of the staff and producer witnesses, which have been considered herein. For flowing gas-well gas cost, they range from a low of 12.1¢

to a high of 21.7¢ per Mcf. For nationwide cost of new gas-well gas, they range from a low of 16.5¢ to 26.2¢. (20:2573-74.) Foster said, "As points of departure, I gave no greater weight to any one [cost] estimate than to another. . . . and in the end came up with results which for flowing gas were 24 percent above the Staff estimate and 27 percent below Mr. Auten's estimate representing his lowest figure." (49:5190.)

However, the witness only paid lip service to the cost evidence. Actually, he did not use the cost estimates as points of departure; rather he treated them as largely meaningless, and hence valueless in determining rates. For example, he testified:

> ". . . I am not saying, and I have never said, that the just and reasonable price of gas at points of production should be measured by cost as a formula." (49:5178.)
>
> "Neither I nor you, Mr. Examiner, nor the Commission, can rationally evaluate these different divergent points of departure [*i.e.*, cost estimates] and give greater weight to the one or the other. You have to look to evidence of what is reasonable, which is independent of these points of departure, and that is precisely what I have done, and reached an end result in between them." (49:5262.)
>
> ". . . the price in this circumstance is not to be determined by a cost figure . . . . The cost figures don't mean anything when they are unavoidably the product of trying to separate common and joint cost as between two binds of output, ..." (49:5263.)

The mere fact that Foster's rate recommendations fall within the extreme range of the cost estimates in the record is no evidence that costs were a factor in arriving at his recommendations. Obviously, the witness' rate proposal stands on a footing which is independent of cost

estimates and would not be affected by any cost findings made by the Commission.

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In *Permian*, 34 F.P.C., at 180-183, the Commission held that in the absence of effective producer price competition, evidence as to contract prices coupled with opinion testimony as to the need for a price comparable to them to induce exploration and development, was insufficient to warrant a finding that such price is just and reasonable within the intendment of the Natural Gas Act. The Commission relied, *inter alia*, on *Bel Oil Corporation* v. *Federal Power Commission* (C.A. 5), 255 F.2d 548, 553, certiorari denied 358 U.S. 804; and *Forest Oil Corporation* v. *Federal Power Commission* (C.A. 5), 263 F.2d 622. See also, *Episcopal Theological Seminary* v. *Federal Power Commission* (C.A.D.C.), 269 F.2d 228, 235-36, certiorari denied *sub nom. Pan American Petroleum Corporation* v. *Federal Power Commission*, 361 U.S. 895. In light of this holding and the federal cases cited, the evidence presented by the witness respecting contract price history and his expression of opinion that the higher range of regulated prices is necessary to bring forth increased supplies, are insufficient to sustain his rate recommendations.[37]

[37] The adequacy and, indeed, liberally of the rates prescribed herein, as inducements to explore and develop; and the ineffectiveness as "incentives" of the rates sought by the producer group and AGD, have been treated of, *supra*, pages 24-28. To the evidence there considered, the following is added: Although the average price paid by by pipelines in Mississippi rose from 10.7¢ per Mcf in 1956 to 20.99¢ in 1961 (with a decline thereafter to 18.51¢ in 1966), there was a decline in annual volumes purchased from 180 million Mcf in 1956 to 151 million Mcf in 1961 and 129 million Mcf in 1966. (Ex. 60, Sch. 7.) Was this decline in pipeline purchases, despite the price increases, because Mississippi is essentially an oil province?

Foster gave other testimony respecting the relationship of price structures in the Other Southwest Area with prices in other sectors of the market, particularly between the price structures in Mississippi and that in southern Louisiana. He said that a Mississippi ceiling price of 22.6¢ for new and flowing gas "has a reasonable relationship with the price structure in Southern Louisiana." (20:2622.)[38] In similar vein, AGD

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witness Frazier recommended that the new gas price here be fixed in "appropriate relationship" to the ceilings set in Southern Louisiana and Texas District 3. More particularly, his position is that the ceilings to be adopted for Texas Districts 5 and 6, northern Louisiana, and Mississippi "should not be in excess of—and preferably should be somewhat less than—the additional cost of transportation from Texas District 3 and southern Louisiana." (50:5402.) Producer witness Charles G. Daley recommended that prices in northern Louisiana be no less than in southern Louisiana, and that the ceilings in Pricing Area 1 be no lower than Hugoton-Anadarko Area rates. (50:5328, 5335-36.) Such proposals would, in effect, employ prices established in other areas, adjusted by relative transportation costs, as the primary determinant for just and reasonable rates in the Other Southwest Area, instead of the cost of gas production determined in this proceeding. The Examiner rejects these recommendations. They fly in the face of the hold-

[38] Interestingly, in their briefs the producers stick to Foster's recommendation of a 22.6¢ ceiling price for Mississippi even though, after he testified, the Commission in *Southern Louisiana*, Opinion 546, adopted a ceiling price for flowing gas of 18.5¢; and for new gas-well gas, ceiling prices of 19.5¢ and 20¢.

ings in *Permian* and *Southern Louisiana* that a cost determination is "the bedrock on which a regulated price must be established," the "basic ingredient." (*Supra*, p. 94.)

"*Location Factor.*" In their main brief, citing testimony of their witness Frazier, AGD argue that "the greater proximity of this area to the principal market centers suggests that the higher field price may not necessarily result in a delivered price any higher than that applicable to gas from more remote areas such as, for example, South Texas." (P. 47.) In their reply brief they say that Pricing Areas 2 and 3 are "more convenient to the major gas market centers" than is Southern Louisiana, and that such circumstance is reason for "imposing price ceilings not lower than those adopted in the adjacent areas." (P. 33.) However, Frazier takes the position that the ultimate customer should not be deprived "of the entire benefit of the transportation saving." (54:5833.) The producers say that Mississippi has a "transportation cost advantage" and is "well located with reference to the eastern markets." (Prod. Br., 255.) Other testimony along this line has been referred to under the immediately preceding subhead.

Insofar as AGD and the producer group may be relying on a "location factor" approach to justify the rates for which they contend, their position conflicts with *Permian*, 34 F.P.C., at 207. There, the Commission said, "No adjustment for 'location factor,' whatever that vague concept may mean, is required or is appropriate in this proceeding, either in the amount prescribed by the examiner or in any other amount." The position of AGD and the producers also conflicts with *Southern Louisiana*, Opinion 546, mimeo., 134-35. In addition, there is no showing in the record how a cost determination of gas

production could be properly adjusted to reflect a claimed "transportation cost

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advantage" or claimed location value of reserves in various parts of the Other Southwest Area.

"*Sharp and Abrupt Departures.*" Mention is made in some of the briefs of an expression in *Permian*, 34 F.P.C., at 190, that, "There is . . . a need to exercise judgment in the design of the rates to avoid unnecessarily sharp and abrupt departures from existing pricing patterns and the business and community dislocations which could result." The flowing-gas rate for Mississippi is the only rate prescribed herein which can be said to be a sharp or abrupt departure from existing pricing patterns.[39] According to the evidence, the average contract price as of January 31, 1966 in Mississippi is 21.79¢, about 5¢ per Mcf above the flowing-gas ceiling fixed herein.

[39] As shown by a comparison with negotiated initial prices, the ceilings for new gas-well gas adopted in this decision do not impose any sharp departures. The ceiling rate prescribed for pipeline quality gathered new gas-well gas in Mississippi is 18.25¢ per Mcf. This level is higher than the weighted average initial contract price in Mississippi for every year since 1962. (Ex. 51, p. 2.) The ceiling rate herein adopted for gathered new gas-well gas in northern Louisiana is 19.6¢ (at 15.025 psia). The weighted average initial contract price in northern Louisiana during the period 1958-1967 never exceeded the 1959 level of 18.1¢ (at 15.025 psia). In the remaining pricing areas of the Other Southwest Area, the new-gas ceilings herein prescribed are consistently and substantially higher than weighted average initial contract prices during the years 1958-1967. Respecting flowing gas, the weighted average contract prices as of January 31, 1966 for contracts dated prior to January 1, 1961, are less than the ceiling prices prescribed herein for pipeline quality gathered gas for all parts of the Other Southwest Area with the exception of Mississippi. (Ex. 51, p. 31.)

This departure from the existing pricing pattern is meet and right; the language in *Permian* is immaterial for several reasons. First, the expression in *Permian* is *dictum*. The Commission was not there faced with the problem of a "sharp" or "abrupt" departure.

Second, while the Examiner is not clear as to what the Commission had in mind in its use of the quoted expression, it may have had in contemplation the objections advanced by Texas and New Mexico that prices should not be set which would cause a cessation or curtailment of drilling activities to the serious injury of the economy of the Permian Basin, and that the States would suffer severe losses in taxes. (Similar arguments are made by Texas in this proceeding.) On petitions for review of

the Commission's final order in *Permian*, the Court of Appeals rejected the states' contentions. *Skelly Oil Company* v. *Federal Power Commission*, 375 F.2d 6, 18. The Supreme Court did not disturb this holding.

Third, in any event the sentence in question must be read in conjunction with the provisions of Section 4(a) of the Natural Gas Act: "All rates and charges made, demanded, or received by any natural-gas company for or in connection with the . . . sale of natural gas subject to the jurisdiction of the Commission . . . shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful." Manifestly, there was no intention on the part of the Commission to contravene those provisions. The Comission did not say that in designing rates there is a need to exercise judgment "to avoid sharp and abrupt departures from existing pricing patterns"; it said there is a need to exercise judgment "to avoid *unnecessarily*

sharp and abrupt departures from existing pricing patterns." [40] By necessary implication, the Commission can, and should, prescribe a rate which causes a sharp and abrupt departure from an existing pricing pattern when otherwise the rate would not be just and reasonable. Any other construction of the Commission's language would conflict with Section 4(a). Here, under the Examiner's finding, the just and reasonable rate in Mississippi for gathered flowing gas, based on cost, is 16.75¢. Hence, the average contract price, 21.79¢, is unjust, unreasonable, and unlawful; and should be vitiated even if a sharp and abrupt departure in pricing patterns results.

Guideline and In-Line Prices. The producer group point out that the Commission's guideline and in-line prices for Mississippi—21.50¢ and 20.6¢, respectively—are higher than for Southern Louisiana and are the highest for any subarea in the southwest market. (Prod. Br., 253.) These circumstances are immaterial. As the Commission noted in *Permian*, 34 F.P.C., at 175, "guideline prices did not purport to be the just and reasonable rates but rather the interim guides the Commission would follow in issuing certificates and in deciding whether to suspend rate increases until just and reasonable rates could be determined after hearing in area rate proceedings." As to in-line prices, in *Federal Power Commission* v. *Sunray DX Oil Company*, 391 U.S. 9, 25, speaking of such prices, the Supreme

[40] The average prices as of January 31, 1966 shown by Foster for pre-1961 contracts have resulted in part from operation of contractual price escalation provisions, including favored-nation and redetermination provisions. (Ex. 51, p. 46.)

Court said:

> "At one time, the Commission apparently hoped that by receiving abridged cost evidence it could establish maximum initial prices which would be near approximations of the just and reasonable rates which would later be established. The Commission eventually concluded that this hope was ill-founded, and in *Callery* this Court approved the Commission's exclusion of cost data from certification hearings. See 382 U.S., at 228 and n. 3.
>
> "In view of the Commission's decision to rely solely upon contemporaneous contract prices in setting initial rates, there can be no assurance that an initial price arrived at by the Commision will bear any particular relationship to the just and reasonable rate."

There is nothing in the briefs of the producer group and AGD or in the testimony of their witnesses which warrants any departure from a cost-determined ceiling price.

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FINDINGS AND CONCLUSIONS

Upon consideration of the evidence adduced and the briefs of counsel, it is further found and concluded that:

(1) Each of the respondents [41] listed in Appendix A or C to this decision is a "natural-gas company"

[41] Where the term "respondents" is used in the finding and ordering paragraphs hereinafter set out, it is to be regarded as referring to all named respondents in the Commission orders issued in this proceeding, and to all parties on whose behalf such named respondents have filed FPC gas rate schedules for sales of gas produced in the Other Southwest Area.

within the meaning of the Natural Gas Act; and is engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption, subject to the jurisdiction of the Commission.

(2) Past, present, and proposed sales of natural gas to which the order herein applies are subject to the jurisdiction of the Commission.

(3) The Other Southwest Area comprises: (a) The State of Mississippi; (b) Northwest Alabama, consisting of Marion, Fayette, Lamar and Pickens Counties; (c) Northern Louisiana, consisting of that portion of Louisiana lying north of the 31 degree parallel through Concordia, Pointe Coupee, Avoyelles, Rapides, and Vernon Parishes; (d) Texas Railroad Commission Districts Nos. 5, 6, and 9; (e) Other Oklahoma, consisting of Adair, Atoka, Bryan, Carter, Cherokee, Choctaw, Cleveland, Coal, Comanche, Cotton, Craig, Creek, Delaware, Garvin, Greer, Harmon, Haskell, Hughes, Jackson, Jefferson, Johnston, Kay, Kiowa, Latimer, Le Flore, Lincoln, Logan, Love, Mclain, McCurtain, McIntosh, Marshall, Mayes, Murray, Muskogee, Noble, Nowata, Okfuskee, Oklahoma, Okmulgee, Osage, Ottawa, Pawnee, Payne, Pittsburgh, Pontotoc, Stephens (except Carter-Knox Area), Tillman, Tulsa, Wagoner, Washington, Pottawatomie, Pushmataha, Rogers, Seminole, and Sequoyah Counties; (f) Northern Arkansas, consisting of Sevier, Howard, Pike, Clark, Dallas, Cleveland, Drew, and Desha Counties, and all other Arkansas counties north of this group; (g) Southern Arkansas, consisting of Little River, Hempstead, Miller, Lafayette, Nevada,

Columbia, Oachita, Union, Calhoun, Bradley, Ashley and Chicot Counties, Arkansas.

(4) "Flowing gas" consists of gas-well gas sold and to be sold pursuant to contracts dated before January 1, 1961, and all casinghead gas, and residue gas derived from either.

(5) "New gas-well gas" consists of gas-well gas sold and to be sold pursuant to contracts dated on or after January 1, 1961.

(6) "Gas-Well gas" means gas from dry-gas reservoirs and gas-condensate reservoirs and gas from gas-cap wells.

(7) Rates for all sales of natural gas, subject to the jurisdiction of the Commission, by the producers in the Other Southwest Area that are above the applicable area rates prescribed herein, have not been shown to be just and reasonable or otherwise lawful under the provisions of the Natural Gas Act, and should be disallowed; and refunds should be required as hereinafter provided.

(8) The just and reasonable rates for past, present, and proposed sales of natural gas to which this order applies are the applicable area rates set out in ordering paragraph (A) below.

(9) Contracts providing for rates in excess of the applicable just and reasonable rates determined herein are in that respect unjust and unreasonable.

(10) It is necessary and appropriate to carry out the provisions of the Natural Gas Act that the orders prescribed herein be adopted.

ORDER

WHEREFORE, IT IS ORDERED, subject to review by the Commission on appeal, or review by the Commission on its own motion, as provided in its Rules of Practice and Procedure, that:

(A) *Base Area Rates.* The following base area rates are hereby established, as of the effective date hereinafter defined, as the just and reasonable rates for sale of gas for resale in interstate commerce by the respondent independent producers in this proceeding, subject to any applicable adjustments for quality as provided in ordering paragraph (B) hereof:

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(1) For pipeline quality flowing gas:

	Cents per Mcf[a] Where Seller Performs Substantial Gathering	Cents per Mcf[a] Where Seller Does Not Perform Substantial Gathering
Pricing Area 1		
Other Oklahoma	17.5	16.0
Texas RRD No. 9	17.8	16.3
Northern Arkansas	17.0	15.5
Pricing Area 2		
Texas RRD Nos. 5 and 6	14.1	13.1
Northern Louisiana	15.8	14.8
Southern Arkansas	13.5	12.5
Pricing Area 3		
Mississippi (onshore) and Northwest Alabama	16.75	15.5

[a]Rates are stated at 14.65 psia, except for Northern Louisiana, Mississippi (onshore), and Northwest Alabama, where they are stated at 15.025 psia.

(2) For pipeline quality new gas-well gas sold and to be sold pursuant to contracts dated on or after January 1, 1961:

	Cents per Mcf* Where Seller Performs Substantial Gathering	Cents per Mcf* Where Seller Does Not Perform Substantial Gathering
Pricing Area 1		
Other Oklahoma	18.4	16.9
Texas RRD No. 9	18.7	17.2
Northern Arkansas	17.8	16.3

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	Cents per Mcf* Where Seller Performs Substantial Gathering	Cents per Mcf* Where Seller Does Not Perform Substantial Gathering
Pricing Area 2		
Texas RRD Nos. 5 and 6	18.1	17.1
Northern Louisiana	19.6	18.6
Southern Arkansas	17.25	16.25
Pricing Area 3		
Mississippi (onshore) and Northwest Alabama	18.25	17.0

(B) *Quality Standards and Adjustments to Base Area Rates.*

(1) The standards for pipeline quality gas are set forth below. The base area rates fixed in paragraph (A) shall be adjusted for any deviations from such standards.

*Rates are stated at 14.65 psia, except for Northern Louisiana, Mississippi (onshore), and Northwest Alabama, where they are stated at 15.025 psia.

(i) *Btu Standards*—Btu standards shall be as follows:

	Btu per Cubic Foot	
(1) Pricing Area	(2) Maximum	(3) Minimum
1	1060	1000
2	1030	1000
3	990	950

These standards shall be applicable to one cubic foot of gas, saturated with water vapor, at 60° F and 14.73 psia.

The increase in the applicable area rate for a given sale shall be proportionate to the amount by which the Btu content exceeds the figure in column (2). The decrease in the applicable rate shall be

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proportionate to the amount by which the Btu content is less than the figure in column (3).

(ii) *Total Sulfur*—The gas shall not contain more than 20 grains of total sulfur per one hundred cubic feet of gas at 60° F and 14.73 psia (200 gr. per Mcf.)

(iii) *Hydrogen Sulfide*—The gas shall not contain more than one grain of hydrogen sulfide per one hundred cubic feet of gas at 60° F and 14.73 psia (10 gr. per Mcf).

(iv) *Water Content*—The gas shall not contain in the aggregate more than seven pounds of water, either in the form of liquid or vapor, per million cubic feet of gas at 60° F and 14.73 psia (.007 lbs. per Mcf).

(v) *Carbon Dioxide*—The gas shall not contain more than 3 percent by volume of carbon dioxide.

(vi) *Other Impurities*—Pipeline quality gas shall contain no oxygen, dirt, dust, gum, or other impurity in sufficient amounts to require the buyer to incur processing costs to eliminate such impurities in order for the gas to meet either customary commercial standards or the customary standards of any of the interstate pipelines in the area.

(vii) *Delivery Pressure*—The gas shall be made available by the seller above the operating pressure of the buyer's pipeline.

(2) When a purchaser buys gas which deviates from the quality standards established in subparagraph (1) above, the base area rate fixed in paragraph (A) shall be adjusted for any deviation from such standards as follows:

(i) The applicable base area rate shall be adjusted downward by the net cost (actually incurred prior to ultimate consumption), of bringign the gas up to standard. If the gas is brought up to standard by the purchaser, a reasonable return upon the net investment should be included as part of the cost incurred in bringing the gas up to pipeline quality. If such processing reduces the volume of the gas, the purchaser shall pay for only the volume remaining after the processing.

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(ii) The applicable base area rate shall be adjusted downward or upward by the amount of

any applicable Btu adjustment as set forth in paragraph (1) (i) above.

(iii) In the case of delivery by seller of gas containing carbon dioxide in excess of the standards herein permitted, notwithstanding anything to the contrary in paragraph (2) (ii), the seller shall have the alternative of receiving payment for the total volume of gas delivered, including the carbon dioxide, provided that the Btu content of the gas is measured before removal of the carbon dioxide for the purposes of the Btu adjustments specified in this order, or receiving payment for the volumes exclusive of the carbon dioxide with the Btu content measured by the volumes of the gas only.

(C) Any seller seeking to charge rates in exces of the applicable area rate or requesting a change in the applicable area rates must file a petition for waiver or amendment of this section pursuant to Section 1.7(b) of the Commission's *Rules of Practice and Procedure* (18 CFR 1.7(b)) fully justifying the relief sought in light of this decision. Unless and until the Commission grants the petition, the seller may not file rate increases in excess of the applicable area rate herein prescribed.

(D) The applicable area rate as defined in ordering paragraph (A) above, shall be effective from and after the effective date hereinafter defined and any amounts collected in excess thereof from and after such effective date shall be subject to refund plus interest at 7 percent. In addition, with respect to the rates involved in the Section 4(e) proceedings set out in Appendix C hereto, the applicable area rate as defined in paragraph (A) above, shall be effective from the date such Section 4(e) rates

were collected subject to refund; and all amounts collected under those Section 4(e) rates, prior to the effective date hereinafter defined, in excess of the applicable area rate shall be subject to refund from the date such excess was collected plus interest at the rate specified in the respective Section 4(e) proceeding, in accordance with the provisions of ordering paragraphs (H) and (I) herein; provided, however, that with respect to such 4(e) dockets no refunds are required below the rate allowed by final order no longer subject to judicial review permanently certificating the sale in question and containing no refund condition.

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(E) Within 45 days from the effective date hereinafter defined each respondent shall file a supplement to each applicable rate schedule, effective as of the effective date hereinafter defined, reflecting any reductions required to bring any or all of its rates into conformity with the applicable base area rate established by ordering paragraph (A) herein.

(F) (1) Each person having on file with this Commission a rate schedule with regard to gas produced or sold within the Other Southwest Area, or hereafter filing such a rate schedule (including a contract or amendment adding acreage or new reserves) shall, with regard to such rate schedule or amendment, file within 90 days from the effective date hereinafter defined, or within 90 days from the date of filing of the rate schedule or amendment, whichever is later, a statement of delivery point and quality conditions in conformity with the findings made herein. The statement shall set

forth either that the gas accords with all pipeline quality standards established herein, or in which respects the gas deviates from the particular quality standards established herein; the agreed cost to the purchaser of processing the gas to bring it to the pipeline quality standards established herein with respect to each quality deviation; any upward or downward Btu adjustment; the point of delivery and the extent of gathering, if any, performed by the seller; and the resulting applicable area rate for the gas. All statements herein required shall be signed by both the seller and the purchaser. If the seller and the purchaser are unable to agree upon any or all of the particulars entering into the computation of the applicable area rate, the seller shall file the statement herein required which shall indicate the absence of agreement and supply the information required to compute the applicable area rate as well as the contentions of the parties with respect to the quality and amount of the adjustment for any item in dispute. The purchaser may file a separate statement setting forth its views within the period herein provided.

(2) The statement filed hereunder which reflects full agreement between the seller and purchaser shall be deemed accepted by the Commission unless the Commission, within 120 days after such filing, shall otherwise order. In the event of disagreement between the seller and the purchaser, or where the Commission otherwise determines that the statement filed is inconsistent with the provisions of ordering paragraph (A) herein, the Commission will after appropriate

proceedings, prescribe the applicable area rate to be applied as of the effective date hereinafter defined.

(3) Any respondent listed in Appendix A or C will be exempt from filing the statement required by subparagraph (1) hereof for any sales which are "small producer sales" as defined in Section 157.40 of the *Regulations under the Natural Gas Act* with respect to sales in the Other Southwest Area in accordance with the amendment to Section 157.40 of the *Regulations* recommended *supra*, at pages 125-26, if a producer seeks to qualify thereunder. If the Commission subsequently finds that such a producer does not qualify as a small producer such applicant shall be required to file the statement required by subparagraph (1) hereof within 90 days after any such Commission finding.

(G) *Moratorium on Rate Increases.* The rates established herein for flowing gas shall be continued until such time as they may be changed by the Commission. For gas-well gas sold and to be sold pursuant to contracts dated on or after January 1, 1961 and any residue gas derived therefrom, no respondent listed in Appendix A or C to this decision shall file any change in rate providing for a price in excess of the applicable area rate prior to (1) a date five years from the date of the Commission's order establishing rates in this proceeding, or (2) a subsequent order of the Commission in this proceeding permitting such filing, whichever is earlier. In no event shall an indefinite pricing provision of the type proscribed by Section 154.93 of the *Regulations under the Natural Gas Act* be

permitted effect to the extent of providing contractual authorization for rate increases, beyond the applicable area rates, subsequent to the expiration of the moratorium. All contracts of the respondents listed in Appendix A or C relating to sales of natural gas subject to the jurisdiction of this Commission and produced in the Other Southwest Area shall be deemed amended, pursuant to Section 5(a) of the Natural Gas Act, by the inclusion of the following language:

> For a period of five years from and after the effective date of the order of the Federal Power Commision in *Other Southwest Area Rate Proceeding*, Docket No. AR67-1, no increase in rates for gas-well sold and to be sold pursuant to contracts dated on or after January 1, 1961, may be filed,

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except in compliance with a specific order of the Commission for a rate in excess of the applicable area rate as determined pursuant to said proceeding or pursuant to later order of the Commission.

(H) *Refund Reports.* Within 120 days from the effective date hereinafter defined a refund report shall be filed with this Commission in triplicate, and one copy served on the buyer, by each respondent involved in one or more of the Section 4(e) proceedings set out in Appendix C to this decision and as to which refunds are required under the terms of this decision. Within 20 days from the filing of the refund report the buyer shall file its written

concurrence or disagreement with such report. The report shall set forth the following information (if more than one rate schedule is involved the respondent shall supply the information for each schedule separately):

(1) The rate collected during the period subject to refund, and the periods during which each rate was collected.

(2) The volume of gas sold at each such rate.

(3) The difference between the total amount collected during the period subject to refund and the amount that would have been collected at the applicable area rate as defined herein, subject to the proviso of ordering paragraph (D). If the seller and buyer do not agree upon the items necessary to the computation of said rate, the seller shall make this computation on the basis of the information supplied by the seller in the statement required by ordering paragraph (F) subject, however, to the terms of subparagraph (2) thereof.

(4) The interest, at rates specified in each Section 4(e) proceeding, on the above refundable excess revenues. In accordance with Section 154.102 (f) of the *Regulations*, no interest shall be required on refundable amounts paid over to the federal and state governments in royalties, except as and to the extent that such authorities pay interest to the producer when refunding overpayments of royalties. Interest due on refunds shall be calculated to the last day of the month preceding the month in which the refund report is required and filed.

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(I) *Treatment of Refunds.* Each respondent shall retain the amounts shown in the report required under ordering paragraph (H) subject to further order of the Commission directing the disposition of those amounts. If a respondent elects to commingle these retained refunds with its general assets and use them for its corporate purposes, it is authorized so to do after notice to the Commission; and it shall pay interest thereon at the rate of 6.5 percent per annum on all funds thus available to the date on which they are paid over to the person ultimately determined to be entitled thereto in a final order of the Commission. If a respondent elects to deposit the retained refunds in a special escrow account, the respondent shall make such deposit and shall tender for filing on or before the date of the filing of the refund report an executed Escrow Agreement, conditioned as set out below accompanied by certificate showing service of a copy thereof upon each of its jurisdictional customers. Unless notified to the contrary by the Secretary within 30 days from the date of filing thereof, the Escrow Agreement shall be deemed to be satisfactory and to have been accepted for filing. The Escrow Agreement shall be entered into between respondent and any bank or trust company used as a depositary for funds of the United States Government and the Agreement shall be conditioned as follows:

(1) Respondent, the bank or trust company, and the successors and assigns of each, shall be held and formally bound unto the Federal Power Commission for the use and benefit of those entitled there-

to, with respect to all amounts and the interest thereon deposited in a special escrow account, subject to such Agreement, and such bank or trust company shall be bound to pay over to such person or persons as may be identified and designated by final order of the Commision and in such manner as may be therein specified, all of any portion of such deposits and the interest thereon.

(2) The bank or trust company shall invest and reinvest such deposits in any short-term indebtedness of the United States or any agency thereof or in any form of obligation guaranteed by the United States which is respectively payable within 180 days as the said bank or trust company in the exercise of its sound discretion may select.

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(3) Such bank or trust company shall be liable only for such interest as the escrowed funds will earn and no other interest may be collected from it.

(4) Such bank or trust company shall be entitled to such compensation as is fair, reasonable and customary for its services as such, which compensation shall be paid out of the escrow account to such bank or trust company. Said bank or trust company shall likewise be entitled to reimbursement for its reasonable expenses necessarily incurred in the administration of this escrow account, which reimbursement shall be made out of the escrow account.

(5) Such bank or trust company shall report to the Secretary quarterly, certifying the amount deposited in the trust account for the quarterly period.

(J) These proceedings shall remain open for such further action as may be necessary with respect to individual respondents and such other action as may be necessary in the premises.

(K) The term "effective date hereinafter defined" (as it is used in the ordering paragraphs herein) is the date of the Commission's order establishing rates in this proceeding.

/s/ Howell Purdue
HOWELL PURDUE
Presiding Examiner

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APPENDIX A

RESPONDENT INDEPENDENT PRODUCERS [1]

(As of August 31, 1969)

Adams, N. L., Sr.
Alexander, C. W.
Alexander, E. B., Jr.
Allied Materials Corporation
Alston, Francis H.
Amax Petroleum Corporation
A'Mell Oil Properties
Amerada Petroleum Corporation
Americana Oil & Gas Properties of Texas, Inc.
American Exploration Development Corporation
American Petrofina, Inc.
American Petrofina Company of Texas
American Realty and Petroleum Corporation
American Trading and Production Corporation
Anadarko Production Company
An-Son Corporation
Anderson, Jacqueline
Anderson Petroleum
Andrewski, H. C.
Anisman, M. Trustee
Anisman, Morris
Apache Corporation
Apco Oil Corporation
Argo, M. M.
Arkla Exploration Company
Arrington, J. H.
Ascher, M.
Ashland Oil and Refining Company
Athens, E. J.
Atkins, Katherine Adger
Atlantic Richfield Company
Austral Oil Company, Inc.
B and A Pipe Line Company
Bailey, Virginia Mitchell
Bander, Joe
Barker, Walter L.
Barnes, Earl E.
Barnwell Debardeleben Oil Company
Barnwell and Kinzler
Barnwell Inc.
Barnwell Production Company
Barrett, Charlotte Osborn
Basin Operating Company
Bass, Harry W.
Thelma Bauerdorf and Constance Cartwright Trustees for George F. Bauerdorf, Deceased
Beacon Oil & Refining Company

[1] All persons named herein and all parties on whose behalf such persons have filed FPC gas rate schedules for sales of gas produced in the Other Southwest Area are respondents in this proceeding.

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Beall, Alton G.
Beard Oil Company
Behring's Production Company, Inc.
Belgam Oil Company, Inc.
Berry, Thomas E.
Biedenharn, Betty Osborn
Big Chief Drilling Company
Biggs, Robert A., Jr.
Biglane, D. A.
Blair, B. B.
Bodcaw Company
Bohnsack, Richard L.
Bond, Durbin
Bond, Roland S.
Borden, S. P.
Boteler, R. H.
Boteler, R. T.
Bracken Oil Company
Brandenburg, R. P.
Breckenridge Gasoline Company
Brennan, Harry W., Jr.
Brian, C. A.
Bridewell, Billy
Brightwell, Donald
Powel Brisco Inc.
Briscoe, Roy E.
Bristol, R. A.
Brooks, Jesse M.
Brooks, Jesse M. & M. James Brooks
Zach Brooks Drilling Company
Brown, George R.
Brown, L. D. and Trant, Sam
Broyles, C. W.
Broyles, Harvey
Bryant, W. H.
Buckwalter, Charles F.
Burk Gas Corporation
Burk Royalty Company
Burnett, T. C. and Ruby C., Estate
Burnham, Joe M.
Burns, L. T., Estate
Burns, R. G.
Burton, C. P.
Butler, J. R.
J. R. Butler and Company
C. F. and H. Oil Company, Inc.
Caddo Pine Island Corporation
California Company, a Division of Chevron Oil Company, The
Inez Calmes Executirix of the Estate of Kermit Calmes, Deceased
Calto Oil Company
Calvert-Mid American Inc.
Cameron, A. A. d/b/a Cameron Oil Company
George E. Cameron Inc.
Canary, S. C.
Cararas, Jerome A.
Caraway, Reagan J.
Cargill, Robert
Carpenter, E. M.
Carter-Jones Drilling Company, Inc.
Car-Tex Producing Company
Caruthers, J. D.
Caruthers Operating Company, Inc.
Carver, Mrs. Helen d/b/a Anthony Oil Company
Casey, Carl
Caska Corporation

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Cassard, A. R.
Central Commercial Company
Central Oil Company
Champlin Petroleum Company
Chastain, M. E.
Chicago Mill & Lumber Company

Chisholm, Alexander F.
A. F. Chisholm d/b/a The Brandon Company
Cities Service Company
Cities Service Oil Company
Citizens Bank of Hattiesburg, Mississippi
Claiborne Gasoline Company
Clark, Anson L.
Clark and Cowden
Clark, F. A.
Clay, Thomas W. and Walker, J. G. d/b/a Clay-Walker
Clearly Petroleum Corporation
Cloud, Robert E.
Coastal States Gas Producing Company
Coats, Alton
Cochran, Phil K.
Coffield, H. H.
Cohen, Don
Coles, Marvin J.
Coles, Otis C., Jr.
Collins, George Fulton, Jr.
Commercial Solvents Corporation
Compadre Oil Corporation
Continental-Emsco Company
Continental Oil Company
Cook, Tom, Jr.
Cook, William H.
Cotton, Doyle W., Jr.
Cotton Valley Community
Coulston Drilling Company
Coutant, A. E.
Cox, Edwin L.
Crescent Drilling Company, Inc.
Creslenn Oil Company
Crest Petroleum Inc., Agent
Chrichton, John H.
Criner Processing
Crockett, M. W. and Charles Kelly d/b/a Crockett & Kelly
Crow, Mrs. Cordelia K.
Crow, David, Trustee
Crow Drilling and Producing Company
Milton Crow Inc.
Crystal Oil and Land Company
Culpepper, Curtis
Curry, W. C.
Cuttycham Oil & Gas Corporation
Cyprus Mines Corporation
Dal-Rock Production Company
Darby, Beulah K.
Daube, Olive H. d/b/a Daube Company
Davidor & Davidor, Inc.
Davis, C. D.
Davis, Paul R. and Lester B. Wood
Davis, Waymon L.
Debardeleben, Charles F. Jr.
Dees, M. H.
Delaney, W. A., Jr.
Delta Drilling Company
Delta Gulf Drilling Company
Deposit Guarantee Bank & Trust Company

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Despot, George J.
Dial, J. B.
Discovery Oil & Gas Company, Inc.
Dorchester Gas Protection Company
Dorfman, Elizabeth F., Trust
Dorfman, Louis
Dorfman, Sam Y., Jr.
Draughn, Paul V., Jr.
Draughn, Paul V., Sr.
Dugan, Thomas
Dunbar, Blaine
N. V. Duncan Drilling Company

Estate of N. V. Duncan
Duncan, Walter
E. Dunlap, Jr.
Eason Oil Company
Ward M. Edinger, Inc.
Edwards, Robert J., Jr.
Elcor Chemical Corporation
Elledge, Vernon and Hall
Ellis, H. A. d/b/a All Star Gas Company
Elm Grove Gathering System Inc.
Erickson, E. L.
Evans, James P., Jr.
Fagadau, Sanford P.
Fair Oil Company
Fairfield Oil Company
Falcon Seaboard Drilling Company
Feazel, W. C., Estate
Felsenthal, S. J., Estate
Fender, Harris R.
Ferguson, Hershal C.
Ferguson Oil Company Inc.
Fields, Bert, Jr.
Fleet, Howard W.
Florsheim, S. L.
Fohs, Julius F. state of
Ford, Evon A.
Helen H. Feldman, Gertrude M. Reilly and Raymond J. Gertz, Trustees, Estate of Joseph Feldman
Forest Oil Corporation
Forgey, R.
Forgotson, James M.
Foster, W. H.
Four States Drilling Company Inc.
Franks, John
Franks Petroleum, Inc.
Joseph F. Fritz
Fryer and Hanson Drilling Company
Gage, Coke L.
Gammill, Dave
Gant, Walter H.
Gas Rock Corporation
Gas Transmission Company
Genecov, A. S., Trustee
General American Oil Company of Texas
Genere Gas Industries Inc.
Geological Exploration Company
Getty Oil Company
Gibbons, Ed
Gilbert, Arch B.
Glassell, A. C., Sr.
Glassell, Alfred C., Jr.
Glassell and Glassell
Glen Rose Gasoline Company
Godfrey, Roy A.
Goins, J. I.
Gose, Steve

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Gragg Drilling Company
Graokla Gas Corporation
Greenbaum, R. R. d/b/a Time Petroleum Company
Greenville Gasoline Company Inc.
Grigsby, Jack W.
Grimes, Otha H.
Gulf Mobile and Ohio R. R. Company
Gulf Natural Gas Corporation
Gulf Oil Corporation
H & H Oil & Gas Company
Hall, Frank J.
Hall, G. C.
Hall, Stanton A.

Hamill, Claud B.
Hamilton Gas Company
Hamman, Blake
Hamon, Jake L.
Harden, Jack
Hardey, Charles O.
Hargrave, Horace C.
Harper Oil Company
Harris, James W.
Harrison, Wallace
Harvey, W. W. & Sojourner, W. C.
Hawkins, H. L. & H. L., Jr.
Hayes, Marshall A., Jr.
Heape, Gene
The Hefner Company
Heidelberg, Cecil F., Jr.
Roy Heidelberg II
Heldt, James D.
Helmerich and Payne Inc.
Henry, S. O., Jr.
Herold, Simon
Maxwell Herring Drilling Corporation
Hewell, W. A., Trustee
Hibbert, R. E., Agent
Hilburn, C. A.
Hinton, Charles A.
Hinton Producing Company
A. J. Hodges Industries Inc.
Hodges, R. M.
Mrs. Luna T. Holcomb
Hollandsworth, G. J.
Hollandsworth and Travis
Holleman, Jeanne Washburn
Home-Stake Production Company
Hood, F. M.
Hooper, S. J.
Houston Royalty Company
J. M. Huber Corporation
Huffines, V. R.
Dudley, J. Hughes
Hughey, W. R.
Humble Oil and Refining Company
Hunt, H. L.
Haroldsen L. Hunt, Jr., Trust Estate
Hassie Hunt Trust
Hunt Industries
Lamar Hunt
Lamar Hunt
Lamar Hunt Trust Estate
Hunt, Nelson Bunker Trust Estate
Hunt Oil Company
Hunt Petroleum Corporation
William Herbert Hunt Trust Estate
The Hunter Company, Inc.
Hunter, James A.
Hurley Oil and Gas Company
Hutton, H. L.

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Ben C. Hyde, Jr.
Hynson, R. C.
Imperial Production Corporation
Inabnet, W. B.
Inger, Henry S.
Ingersoll Power & Fabricating Company Inc.
International Helium Inc.
Investors Oil and Gas Inc.
Investors Royalty Company, Inc.
Jabco Inc.
Jackson, J. E.
Jackson, J. E. Inc.
L. B. Jackson Company
T. L. James and Company, Inc.
Javelin Oil Company, Inc.
The Jaybird Corporation
Jenkins, Charles L.
Jenkins-Ray Supply
Jennings, R. L. and Clogg, M.

d/b/a Jennings and Clogg
Jernigan, J. E. & Morgan M. V. d/b/a Jernigan and Morgan Oil Company
Jernigan and Morgan Transmission Company
Johnson, E. Lyle
Johnson, Gilbert S.
Johnson, Howard C.
Jones, Carroll G.
Jones, James Marshall
Jones, Joseph M.
L. E. Jones Drilling Company
Jones, O'Brien Inc.
Jones, Shelburne and Pellow Oil
Jorden, Jack C., Jr.
Josalin Production Company
Jowoco, Inc.
Karll, R. P.
K. P. Compression Company, Inc.
Keener Oil Company
Kemp, James E.
Kenyon, Clarence
Kerr-McGee Corporation
Ketchum, Ralph F. d/b/a Ketchum Oil Company
Killingsworth, S. H.
King, J. D.
King, Liberto Investments
King, Robert E.
Kinnebrew, Lee
Kinne, M. L.
Kinsey, Norman V.
Kirby Petroleum Company
Kirkpatrick Oil and Gas Company
Kubler, E. C., Jr.
R. Lacy, Inc.
Ladner, Heber
Laffoon Oil Company
La Gloria Oil and Gas Company
P. G. Lake, Inc.
William H. Lambdin
The Lancer Corporation
Landa Oil Company
Langford Drilling Company
Lankford, K. D., Jr.
Larco Drilling Company
Lario Oil and Gas Company
Larson, Perry E. and Max. L. Thomas
Larue, Fred d/b/a Larue-Smith Prod. Co.
Latham, Joe
Latham Management Company, Inc.

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Latimer, D. C.
Lechnar and Hubbard
Le Cuno Oil Corp.
Lee Drilling Company
Lee, R. A. and Ladner, H. L.
Lee, Robert A.
Le Gendre, P. G.
Lemon, I. M., Mrs.
Lerner, W. Zolley d/b/a Ko-Ler Oil Company
Lewis, Ethel May Neel
Lillystrand, T. O., Jr.
The Lincoln Converse Company
Little, Quintin
Livingston Oil Company
Lomac Drilling Company
London Gas Company
Lone Star Producing Company
Longhorn Production Company
Lou-Ala Development Corporation, Inc.
Lubell Oil Company
Lynn Drilling Company
Lyons, C. H., Jr.
Lyons and Logan
Lyons, C. H., Sr.

McAlester Fuel Company
W. C. McBride, Inc.
McCain, M. F.
McCalman Drilling Company, Inc.
McCamic, Charles
McCausland, Oscar B.
McCommons Oil Company
McCommons, William E. d/b/a McCommons Exploration Company
McConnell, D. B.
McCord, Charles T., Jr. d/b/a McCord Oil Company
McCulloch Oil and Corporation of California
McGuire, T. W.
McKnight, Peyton, Jr.
McLemore, B. Regan
McMahon, C. L., Jr.
McMillin, Frank E.
McMurrey, Jim, Estate
McNeish, George R.
McRae, Ethel C.
M & M Producing Company
Machin Oil Ltd.
Mack Oil Company
Mackey, Earl T.
Madole, J. D.
Magna Oil Corporation
MaGuire, Russell, Estate of
Malernee Oil Company
Manziel, Bobby
Manziel, Dorothy N.
Mapco Production Company
Marathon Oil Company
Marcus, Earl
Marks, E. W., Sr.
Marr, M. H.
Marshall Exploration Company Inc.
C. F. Martin Inc.
W. T. Massey and Harry A. Moore d/b/a Massey & Moore
Maynard Oil Company
Mayronne, R. W., Jr. d/b/a Riverside Oil Company
Medallion Oil Company
Menefee, J. M.
Mercury Drilling Company
Merrick, Ward S., Jr.
Mesa Petroleum Company

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Midhurst Oil Corporation
Midway Oil Company
Midwest Oil Corporation
Miles Kimball Company
Miller, Paul L.
Miss-Tex Oil Producers
Mitchell, George and Associates, Inc.
Mitchell, W. H.
Mobil Oil Corporation
Moffatt, Robert J.
Moffitt, Mrs. Tom J.
Moise, Mrs. Leah H.
W. A. Moncrief
Monla Gas Company Inc.
Monroe Gas System Inc.
Monsanto Company
Morgan Brothers
Morgan, Dave
Morgan, J. A.
Morris, C. L.
Morris, P. D.
Mortimer, Mrs. Betty D.
Mosbacher, Robert
Moss, H. S.
Murphy, Charles H., Jr.
Murphy Oil Company of Oklahoma Inc.
Murphy Oil Corporation
Muslow, James
Mutual Investment Company
Myers, Sidney G., Jr.

Nafco Oil and Gas Company Inc.
National Bank of Commerce of Houston
National Oil Company Inc.
Natol Petroleum Corporation
Neal, T. J.
Nemours Corporation
Neustadt, Doris W.
Newton Naval Stores Company, Inc.
Nichols, Irl A.
Nobles, Eulalie M.
Nolan, William C. and T. M.
North Central Oil Corporation
Norton Oil Company Inc.
Norville Oil Company Inc.
Nowery, James R.
O'Boyle, John W.
O'Boyle, Kathleen, Trust No. 2
O'Rourke, D. F.
Occidental Petroleum Corporation
OK and B Drilling Company
Oklahoma Natural Gas Company
Oliver, Rees R.
Oliphant, A. G.
Olympic Oil Company
Onstott, L. J. d/b/a Progress Petroleum Products
Orr, B. B.
Osborn, Jewel
Osborn, W. B., Jr.
W. B. Osborn, Jr., Executor The Estate of W. B. Osborn, Sr.
Owen, K. D.
Oxley, John C.
Ozark Gas Corporation
P. S. and G., Inc.
Page, Wiley
Palmer, Milo, T.
Pan American Petroleum Corporation
Patterson, H. I. and Williams, R. E.

Penn, G. E.
Perkins, Elizabeth
Perkins, J. R.
Permian Corporation
Perritt, H. W.
W. C. Perryman
Petroleum Corporation of Texas
Phillips, B. F., Estate of
Phillips, Jack L.
Phillips, Leonard W.
Phillips, Loyce
Phillips, O. A., Estate of
Phillips Petroleum Company
Pickens, W. L.
Pioneer Oil and Gas Company, Inc.
Pioneer Oil Investment Company
Placid Oil Company
Porter, L. B.
Potter, Tom
Powers, M. F. Estate
Prentice, Paul R.
Prentiss, W. P.
Price, Jack E.
Proctor, Douglas E., Jr.
Pruet, Chesley
Quisenberry, W. Y.
Radford, C. H.
Raigorodsky, Paul M.
Ray, Lucie L.
Raymond Oil Company, Inc.
Read, Paul L.
Reed, M. T.
Republic Royalty Company
Reserve Oil and Gas Company
Reynolds Mining Corporation
Rhoades Oil Company
Richardson Oils, Inc.

Richenthal, Arthur
C. R. Ridgway
Ridgway Management, Inc.
Rimrock Tidelands Inc.
Rio Rojo Gathering System Inc.
River Corporation
Robbins, J. C., Jr.
Robbins Petroleum Corporation
Roberts, J. I.
Roberts and Murphy, Inc.
Robinson, L. L.
Robinson & Marshall Drilling Company
Rogers, Hellena Fox Wright
Roper, Frank C.
Rorem, S. D.
Ross Production Company
Ross, R. M.
Wilhelmina duP. Ross
Rougon, Dr. and Mrs. A. L.
Rowan, J. Mike
Rozeman, A. M.
Rudco Oil and Gas Company
Rudman, Rose
Rushing, J. S.
Ryan, Fred H.
Ryan, P. H.
Ryan, Ray
Samedan Oil Corporation
Martin A. Samuelson
Sanders, Nell E.
Sanford, John T.
Schafer Drilling Company
Schober, Henry I.
Scott, Francis W.
Joseph E. Seagram and Sons, Inc. d/b/a Texas Pacific Oil Company

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Sells Petroleum Inc.
Sellwood and Myers
Service Gas Products Company
Sesco Production Company
Shadid, Fred V.
Shalett, H. T. and Crow, David
Shear, Warren
Shell Oil Company
Shields, Jay M.
Sho Van Gas Producing Company
R. H. Siegfried Inc.
Siesta Oil and Exploration Company, Inc.
Signal Oil & Gas Company
Simmons, D. J. d/b/a Farrell and Company of Louisiana
Simmons, Jay
Simmons, Maxwell D.
Sinclair Oil Corporation
Skeeters, A. Z.
Skelly Oil Company
Skelton, D. W.
Sklar, Sam
Slack, Bob B.
Smith, Douglas V.
Smith, E. D.
Smith, H. S.
Smith, J. J.
Smith, L. E.
Smith Operating & Management Company
Smith, P. E.
Smith, R. E.
Smith, Walter R.
Snee, William E.
Sohio Petroleum Company
Sohoma Natural Gas Company, Inc.
South Central Natural Gas Corporation
Southern Union Production Company
Southwest Gas Producing Company
Stack, J. E., Jr.

R. A. Stacey, Jr.
Standard Oil Company of Texas, a Division of Chevron Oil Company
States Oil Company, Inc.
Stephens Production Company
Stephenson, J. F.
Stewart, Austin E.
D. W. Stewart, Jr., and E. L. Stewart
Strahan Oil and Gas Company, Inc.
Strength, (Mrs.) Janie R.
Harry J. Strief, Estate of
Stringer, Murray D.
Sun Oil Company
Sun Oil Company (DX Division)
Sunset International Petroleum Corporation
The Superior Oil Company
Sutton, Carol Daube
Tacony Company, The
Talbot, C. P.
Tanner, J. W.
Tate, Ernest W.
Taubert, J. E.
Taylor, Mrs. Douglas Havard
Taylor, McCleland
Teekel, Lloyd G.
Tenneco Oil Company
Texaco Inc.

Texas Gas Exploration Corporation
Texas San Juan Oil Corporation
Thomas, Evan A.
Thomason, D.
D. Thomason Production Company, Inc.
Thompson, J. Cleo
Tittle, W. M.
Todd, Dr. John D.
Trahan, J. C.
J. C. Trahan Drilling Contractor Inc.
Trans-State Oil Company, Division of Hess Oil and Chemical Corporation
Trant, Mike d/b/a Mike Trant Drilling Company
Trant, Sam
Treat, Frank B.
Tri J. Inc.
Trice Production Company
Tuttle, R. M. d/b/a R. M. Tuttle Pipe Line
Twin Gas Company
Union Oil Company of California
Union Producing Company
Union Texas Petroleum, a Division of Allied Chemical Corporation
Vanson Production Corporation
Vaughn, G. H., Jr. and Jack C.
Vaughn, G. H., Jr.
Vaughn Petroleum Inc., Agent
Vaughey and Vaughey
Venters, Harley E.
Wager, Dan R.
Walker, Keith F.
Walker, Ross
Wannop, Mary Fitts
Warren Petroleum Corporation
Wegmann, W. A.
Westates Petroleum Company
Westheimer Neustadt Corporation
Westland Oil Development Corporation
Wheless Drilling Company
N. H. Wheless Oil Company
Whitaker, Douglas
Fred Whitaker
White, Blanche N.

White, Janet
White, T. J., Jr.
Whitehall Oil Company, Inc.
Whittington Number Five
Wichita River Oil Corporation
Wiederhold, William C., Agent
Williams, Charles K.
Williams, E. B., Jr.
Williams, E. B., Sr.
Williams, George H. and Hill
Williams Pressure Service Company
Williams, Robert Gordon
Wilson, Bruce L.
Wilson, Norton F.
Winwell Inc.
Wise Operating, Inc., of Tyler
Wolfe Drilling Company
Wood Oil Company
Woods, Harold L.
Woods Petroleum Corporation
Worldwide Petroleum Corporation

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Worth Drilling Company
Wrather, J. D., Jr.
Wunderlich Development Company
W. R. Yinger
Marshall R. Young Oil Company
Zephyr Drilling Corporation
Zephyr Oil Company

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APPENDIX B

RESPONDENT PIPELINE PURCHASERS

Arkansas Louisiana Gas Company
Cimarron Transmission Company
Cities Service Gas Company
Cushing Gas Transmission Company
El Paso Natural Gas Company
Fort Smith Gas Corporation
(now Arkansas Oklahoma Gas Corporation)
Humble Gas Transmission Company
Lone Star Gas Company
Louisiana Nevada Transit Company
Michigan Wisconsin Pipe Line Company
Mississippi River Transmission Corporation
Natural Gas Pipeline Company of America
Panhandle Eastern Pipe Line Company
Rio Sabine, Incorporated
Southern Natural Gas Company
Tennessee Gas Pipeline Company, A Division of Tenneco Inc.
Tensas Gas Gathering Corporation
Texas Eastern Transmission Corporation
Texas Gas Transmission Corporation
Trunkline Gas Company
Union Gas System, Incorporated
United Fuel Gas Company
United Gas Pipe Line Company
Valley Gas Transmission, Incorporated

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APPENDIX C

SECTION 4(E) RATE SUSPENSION PROCEEDINGS[1] CONSOLIDATED FOR HEARING WITH AREA RATE PROCEEDING (OTHER SOUTHWEST AREA), DOCKET NO. AR67-1
(As of August 31, 1969)

Name[2] and Docket Nos.

Amerada Petroleum Corp.; RI65-334
American Petrofina Company of Texas (Oper.), *et al.*; RI64-442
Apache Corporation; RI63-332
Arkla Exploration Co.; RI 64-233, RI64-240, RI64-277, RI66-339
Ashland Oil & Refining Co., *et al.;* RI60-288
Atlantic Richfield Co.; RI60-231, RI61-172, RI64-256, RI65-28, RI66-166, RI66-345
Bander, Joe, *et al.;* RI 67-54
Bond, Durbin; G-20184
Borden, S. P.; G-20191
Bracken Oil Co. (Oper.), *et al.;* G-16084
Bridewell, Billy (Oper.), *et al.;* RI63-241
D. H. Byrd (Oper.); RI64-203
Cameron, A. A. d/b/a Cameron Oil Co., *et al.;* RI 65-521, RI67-80
Carter-Jones Drilling Co., Inc. (Oper.), *et al.;* RI61-546

[1] These proceedings are consolidated only insofar as they pertain to sales in the Other Southwest Area.

[2] This producer designation is for general identification and may not include all of the respondents designated in the respective orders initiating rate suspension proceedings.

Champlin Petroleum Co.; RI63-304
Claiborne Gasoline Co.; RI64-260
Cohen, Don (Oper.), *et al.;* RI64-421
Coles, Marvin J., *et al.;* RI 64-134
Continental Oil Co.; G-19734, G-20197, RI60-193, RI60-223, RI61-249, RI63-217, RI63-350, RI63-368, RI64-165, RI64-166, RI64-784, RI67-72

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Continental Oil Co. (Oper.), *et al.;* RI63-240, RI65-128
Continental Oil Co. (Oper.) and Clinton Oil Co. (Oper.); RI65-231
Cox, Edwin L.; RI63-219, RI63-428, RI64-68, RI64-573
Cyprus Mines Corp. & Skelly Oil Company (Oper.); RI64-8
Coastal States Producing Company; RI67-159
Davis, C. D., *et al.*, and Car-Tex Producing Co., *et al.;* RI65-374
Draughn, Paul V., Jr.; RI65-424
Draughn, Paul V., Sr.; RI65-422
Dugan, Thomas A.; RI65-600
Ells, H. A., *et al.*, d/b/a All Star Gas Company and Signal Oil and Gas Company; RI63-178
Falcon Seaboard Drilling Co., *et al.;* RI63-221
Fields, Bert, Jr., *et al.;* RI64-290
Forest Oil Corp.; RI63-230
Forest Oil Corp. (Oper.), *et al.;* RI65-125
Four States Drilling Co., Inc. (Oper.), *et al.;* G-20081
Gant, Walter H. (Oper.), *et al.;* RI64-254
General American Oil Co. of Texas; RI63-377, RI65-345
Getty Oil Co.; RI64-726, RI64-762, RI65-129
Greeneville Gasoline Co., Inc. (Oper.); RI63-275
Gulf Oil Corp.; G-11335, G-13519, G-13581, G-16657, G-19742, G-20560, RI60-214, RI61-169, RI61-212, RI62-114, RI63-148, RI64-198, RI64-231, RI64-247

Gulf Oil & Ashland Oil & Refining Co.; RI65-599
Hall, Stanton A.; RI65-421
Hamman, Blake (Oper.), *et al.;* RI64-710
Harper Oil Co. (Oper.), *et al.;* RI 63-450, RI65-274
Hefner Co. The (Oper.) *et al.* and Sun Oil Co.; RI63-472
Helmerich & Payne Inc. (Oper.), *et al.;* RI63-445
Home-Stake Production Co. OEA and Wolfe Drilling Co. OEA; RI64-124

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Humble Oil and Refining Co. (Oper.), *et al.;* RI66-24, RI66-279, RI67-108
Humble Oil and Refining Co. and Texaco Inc.; RI66-149
Hunt, H. L., *et al.;* RI61-203, RI62-136, RI64-44, RI66-131
Haroldson L. Hunt, Jr., Tr. Est.; RI66-239, RI67-180
Hassie Hunt Trust; G-19752, RI61-206, RI63-104, RI64-213, RI65-265, RI67-100
Hassie Hunt Trust (Oper.), *et al.;* RI66-130
Lamar Hunt Trust Estate, *et al.;* RI66-240, RI67-181
Hunt, Nelson Bunker Trust Estate; RI66-241, RI67-182
Hunt Oil Co.; RI63-229, RI66-127, RI66-243, RI67-98, RI67-178, RI67-179
Hunt Oil Co. (Oper.), *et al.;* RI66-237, RI66-270
Hunt Oil Co., *et al.;* RI66-242
Hunt Petroleum Corp.; RI65-261
Hunt, William Herbert Trust Estate; RI66-238, RI67-183
Hunter Co., Inc., The; G-19920
Hurley Oil & Gas, *et al.;* G-16645
Hurley Oil & Gas (Oper.), *et al.;* & Mobil Oil Corporation; RI62-318, RI64-201
Hyde, Ben C. W., Jr. (Oper.); RI63-279
T. L. James & Co., Inc., *et al.;* RI66-172, RI66-173

Jernigan, J. E. & Morgan, M. V., d/b/a Jernigan & Morgan Oil Co.; RI63-233
Jernigan & Morgan Transmission Co.; RI63-234
R. Lacy, Inc., *et al.;* G-14315
Laffoon Oil Co.; RI64-689
Landa Oil Co.; G-19028, RI64-730, RI64-740, RI65-397
Lario Oil & Gas Co.; RI64-601
D. C. Latimer; RI61-410
LeCuno Oil Corp.; RI60-459
LeCuno Oil Corp., & Landa Oil Co.; RI61-210
London Gas Co., *et al.;* RI61-112, RI63-176, RI63-177
McCommons Oil Co., *et al.;* RI64-21, RI65-568
McCommons, W. E., d/b/a McCommons Exploration Co., *et al.;* RI63-281

Mack Oil Co.; RI64-18
Mapco Production Co. (Oper.), *et al.;* RI66-20
Marathon Oil Co.; RI66-140, RI67-121, RI66-33, RI66-74
Marathon Oil Co. (Oper.), *et al.;* RI66-19
Marks, E. W., Sr., *et al.;* RI62-272
Marr, M. H.; RI66-144
C. F. Martin, Inc.; RI65-372
Maynard Oil Co.; RI64-288, RI67-17, RI67-18
Maynard Oil Co. (Oper.), *et al.;* RI64-287, RI66-10
Midway Oil Co., *et al.;* RI64-87
Midwest Oil Corp.; RI64-195
Midwest Oil Corp. (Oper.), *et al.;* RI64-214
George Mitchell & Associates, Inc., Agent for Ann W. Alexander, Executrix, *et al.;* RI61-239
Mobil Oil Corp.; RI61-113, RI61-188, RI65-196
Mobil Oil Corp. (Oper.), *et al.;* RI61-114, RI64-210, RI 65-276, RI66-98
Mortimer, Mrs. Betty D., *et al.;* G-20194

Murphy Oil Corp., *et al.*; RI61-145
Murphy Oil Corporation; RI61-146
Newton Naval Stores Co., Inc.; RI65-346
North Central Oil Corp., *et al.*; G-19026
Norville Oil Co., Inc.; RI64-19
Pan American Petroleum Corp.; G-13516, G-16629, G-17058, G-19641, G-19765, RI61-167, RI61-192, RI62-151, RI63-81, RI63-138, RI63-231, RI64-222, RI64-231, RI65-178, RI65-277, RI65-294, RI66-129
Perkins, Elizabeth, *et al.*; RI64-114
Phillips Petroleum Co.; G-12283, G-16112, G-16113, RI60-257, RI63-394, RI64-619, RI65-577, RI66-324
Phillips Petroleum Co. (Oper.), *et al.*; RI61-284, RI67-173
Phillips Petroleum Co., and Moran Pipe and Supply Co., Inc.; RI65-127
Pioneer Oil & Gas Co., Inc., *et al.*; G-20195, RI61-51

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Placid Oil Co. (Oper.), *et al.*; G-17423, G-19767, RI61-176, RI61-213, RI62-104, RI64-202, G-15370
Ridgway, C. R. & W. B.; G-19932
Ridgway Management Inc.; G-20068
Rimrock Tidelands Inc., *et al.*; G-15073
Robins, J. C., Jr.; RI63-475
Robbins Petroleum Corp., Pan American Petroleum Corp., OEA, and Amerada Petroleum Corp.; RI63-476
Roper, Frank C.; RI60-389
Ross, R. M.; RI65-318
Rowan, J. Mike (Oper.), *et al.*; RI63-293
Ruffin, J. F., Jr., Trustee; G-20192
Samedan Oil Corp.; RI63-466, RI63-467
Joseph E. Seagram Sons Inc., d/b/a Texas Pacific Oil Co.; RI63-183, RI63-443
Shell Oil Co.; RI64-791, RI65-474, RI65-477

Shell Oil Co. (Oper.); RI65-485
Shell Oil Co. (Oper.), *et al.;* RI66-14
Shell Oil Co. and Okmar Oil Co., *et al.*; RI65-483
Shell Oil Co. OEA and R. E. Hubbard, Jr., OEA; RI65-476
Shell Oil Co., Cabot Corp. (SW) OEA, Herman George Kaiser OEA, Phillips Petroleum Co., V. F. Neuhaus, R. E. Hubbard, Jr., and Okmar Oil Co., *et al.;* RI65-475
R. H. Siegfried Inc., *et al.;* RI62-380, RI64-677
Signal Oil & Gas Co.; RI63-464, RI63-465
Simons, Maxwell D. (Oper.), *et al.*; RI63-477
Sinclair Oil Corp.; RI61-530, RI62-152, RI63-131, RI64-257, RI65-14, RI65-38, RI66-77, RI66-86, RI66-345
Skelly Oil Co.; RI60-253, RI67-10
Sohio Petroleum Co.; RI66-276, RI67-81
Southern Union Production Co.; RI65-587
Southwest Gas Producing Co., Inc.; RI66-351
Southwestern Exploration Consultants Inc. (Oper.), *et al.;* RI60-245, RI60-360
Standard Oil Co. of Texas, Division of Chevron Oil Co.; RI63-462
Sun Oil Company; RI66-401

Sunray DX Oil Co.; RI64-335
Sunset International Petroleum Corp.; RI61-545
The Superior Oil Co.; G-20347, RI61-83
The Superior Oil Co. (Nevada) and James W. Harris; G-14106
The Superior Oil Co. and Gas Rock Corporation; G-18694
Ernest W. Tate; RI66-357
Tenneco Oil Co.; RI63-474, RI65-145

Tenneco Oil Co. (Oper.), *et al.;* RI64-741, RI65-534, RI66-87, RI66-369
Tenneco Oil Co., Continental Oil Co.; RI62-539
Texaco Inc.; RI66-329, RI66-383, RI67-2
Todd, Dr. John D.; RI60-352
J. C. Trahan Drilling Contractor, Inc. & Marshall R. Young Oil Co.; RI61-499, RI64-722
J. C. Trahan Drilling Contractor, Inc. (Oper.), *et al.;* RI63-21, RI64-329, RI64-380, RI65-548
Twin Gas Co.; RI63-464
Twin Gas Co. (Oper.); RI63-465
Union Oil Co. of California (Oper.), *et al.;* RI66-317, RI66-426
Union Oil Co. of California and May Petroleum, Inc., and Ashland Oil and Refining Co.; RI66-316
Union Texas Petroleum Division of Allied Chemical Corp. (Oper.), *et al.;* RI64-742
Union Texas Petroleum Division of Allied Chemical Corp., and Singer-Fleischaker Oil Co., *et al.;* RI65-126
Union Texas Petroleum Division of Allied Chemical Corp., *et al.;* RI63-461
Vaughn, G. H., Jr., *et al.;* RI61-182
Venters, Harley E.; RI66-356
Walker, Ross; RI65-499
Whelan, D. E. and R. J.; RI62-39
Wichita River Oil Corp.; RI64-151
Wunderlich Development Co. (Oper.), *et al.*, and Clinton Oil Co.; RI65-124

APPENDIX D

THE "BIG DIVISOR" ISSUE IN PROCESSING COSTS

The correctness of Engel's result may be demonstrated by taking the residue sales volume in pricing area (1) of 22,654,070 Mcf, breaking it down into estimated volumes subjected to the various processing functions on the basis of volumetric relationships shown in Engel's plant sample (Ex. 60, Sch. 3, sheet 7), and multiplying the estimated functional volumes by respective functional unit processing shown by Engel. The resulting total processing cost is $445,423, as compared with $446,285 shown by Engel (Ex. 60, Sch. 3, sheet 1).

[11,503]

	Engel's Plant Sample Volumes (MMcf) (1)	Relationship to Total Output (%) (2)	Breakdown of Residue Sales (MMcf) (3)	Unit Cost (¢/Mcf) (4)	Processing Cost ($) (5)
Compression	109,279.2	75.1	17,013.2	2.345	398,960
Treating	14,726.0	10.1	2,288.1	0.590	13,500
Dehydration	140,487.2	96.5	21,861.2	0.129	28,201
Residue R & D	133,019.2	91.4	20,705.8	0.023	4,762
Total Residue Output	145,570.4				
Residue Sales			22,654.1		
Total Processing Cost					445,423

[11,504]

APPENDIX E

[11,505]

[11,506]

APPENDIX F

Cost of Pipeline Quality Flowing Gas-Well Gas for Pricing Area 1

	Unit Cost ¢/Mcf
Production Cost	10.11
E&D	4.01
Regulatory Expense	0.17
Subtotal	14.29
Producer Plant Processing	0.81[1]
Pipeline Incurred Conditioning Costs	0.05[2]
Total Before Gathering and Taxes	15.15
Gathering Allowance	1.50
Total Cost Before Taxes (14.65 psia)	16.65

	Okla.	Texas #9	N. Ark.
Tax Base	15.15	15.15	—
Tax Rate	5% + 0.04¢	7%	0.35¢
Tax Allowance	0.84	1.14	0.35
Total Cost (14.65 psia)	17.49	17.79	17.00

[1] Appendix E, p. 1.

[2] Ex. 60, Sch. 3, sheet 1, line 16, adjusted to reflect dehydration of 19,141,010 Mcf rather than 9,768,636 Mcf.

[11,507]

Cost of Pipeline Quality Flowing Gas-Well Gas for Pricing Area 2

	Unit Cost ¢/Mcf
Production Cost	7.45
E&D	4.01
Regulatory Expense	0.17
Subtotal	11.63
Producer Plant Processing	0.46[1]
Pipeline Incurred Conditioning Costs	0.27[2]
Total Before Gathering and Taxes	12.36
Gathering	
Plant	0.34[3]
Separate System	0.08[4]
Pipeline Incurred	0.35[5]
Total Cost Before Taxes (14.65 psia)	13.13
Total Cost Before Taxes (15.025 psia)	13.47

	Texas 5 & 6	N. La.	S. Ark.
Tax Base	12.36		
Tax Rate	7%	2.30¢	0.35¢
Tax Allowance	0.93	2.30	0.35
Total Cost (14.65 psia)	14.06	—	13.48
Total Cost (15.025 psia)	—	15.77	—

[1] Appendix E, p. 2.

[2] Ex. 60, Sch. 3, sheet 2, line 17, adjusted to reflect dehydration of 216,568,438 Mcf rather than 165,433,703 Mcf.

[3] Appendix F, p. 2.

[4] Ex. 60, Sch. 3, sheet 2; line 9, col. (d) ÷ line 4, col. (b).

[5] Ex. 60, Sch. 3, sheet 2; line 18, col. (d) ÷ line 4, col. (b).

[11,508]

Cost of Pipeline Quality Flowing
Gas-Well Gas in Pricing Area 3

	Unit Cost ¢/Mcf
Production Cost	9.57
E&D	4.01
Regulatory Expense	0.17
Subtotal	13.75
Producer Plant Processing	0.00[1]
Pipeline Incurred Conditioning Costs	0.43[2]
Total Before Gathering and Taxes (14.65 psia)	14.18
Total Before Gathering and Taxes (15.025 psia)	14.54
Gathering Allowance	1.25
Total Cost Before Taxes (15.025 psia)	15.79
Tax Base	14.54
Tax Rate	6%
Tax Allowance	0.93
Total Cost (15.025 psia)	16.72

[1] Ex. 60, Sch. 3, sheet 3; line 6, col. (d) ÷ line 4, col. (b).

[2] Ex. 60, Sch. 3, sheet 3, line 13 adjusted to reflect dehydration of 73,518,672 Mcf rather than 19,930,249 Mcf.

[11,509]

APPENDIX G

Cost of Pipeline Quality
New Gas-Well Gas for Pricing Area 1

	Unit Cost ¢/Mcf
Average Cost Before Royalty and Production Tax	12.97
Plant Processing	0.69[1]
Pipeline Incurred Conditioning	0.05[2]
Subtotal	13.71

	Okla.	Texas #9	N. Ark.
Tax and Royalty Base	13.71	13.71	13.71
Tax Rate	5% + 0.04¢	7%	0.35¢
Royalty @ 14%	2.23	2.23	2.23
Tax	0.88	1.20	0.35
Subtotal	16.82	17.14	16.29
Gathering	1.50	1.50	1.50
Total Cost	18.32	18.64	17.79

[1] Appendix E, p. 1.

[2] Appendix F, p. 1.

[11,510]

Cost of Pipeline Quality
New Gas-Well Gas for Pricing Area 2

	Unit Cost ¢/Mcf
Average Cost Before Royalty and Production Tax	12.97
Plant Processing	0.40[1]
Pipeline Incurred Conditioning	0.27[2]
Subtotal (14.65 psia)	13.64
" (15.025 psia)	13.99

	Texas #5 & 6	N. La.	S. Ark.
Tax and Royalty Base	13.64	13.99	13.64
Tax Rate	7%	2.30¢	0.35¢
Royalty @ 14%	2.22	2.28	2.22
Tax	1.19	2.30	0.35
Subtotal	17.05	18.57	16.21
Gathering	1.0	1.0	1.0
Total Cost (14.65 psia)	18.05		17.21
Total Cost (15.025 psia)		19.57	

[1] Appendix E, p. 2.

[2] Appendix F, p. 2.

[11,511]

Cost of Pipeline Quality
New Gas-Well Gas for Pricing Area 3

	Unit Cost ¢/Mcf
Average Cost Before Royalty and Production Tax	12.97
Plant Processing	0.00
Pipeline Incurred Conditioning	0.43[1]
Subtotal (14.65 psia)	13.40
" (15.025 psia)	13.74
Royalty at 14%	2.24
Tax @ 6%	1.02
Subtotal	17.00
Gathering	1.25
Total Cost	18.25

[1] Appendix F, p. 3.

Errata Notice

[11,512]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

ERRATA NOTICE
(October 31, 1969)

PRESIDING EXAMINER'S INITIAL DECISION
(Issued September 22, 1969)

Page	Line	Correction
1	11	Insert a quotation mark after "Oklahoma"
17	23	Insert a comma after "sound"
26	line 2 of table	Change "North" to "Northern"
	line 5 of table	Change "South" to "Southern"
	line 9 of table	Change "North" to "Northern"
27	5	Change "north" to "northern"
	6	Change "south" to "southern"; change "north" to "northern"
	19	Change "north" to "northern"
	20	Change "south" to "southern"
	21	Change "south" to "southern"
	29	Change "north" to "northern"
29	8	Change "north" to "northern"
30	33	Change "south" to "southern"

[11,512]

Errata Notice

Page	Line	Correction
	34	Change "south" to "southern"
	40	Change "north" to "northern"

[11,513]

31	8	Change "North" to "Northern"
32	1	Change "North" to "northern"
33	41	Delete "No."
58	19	Change line to read, "*Permian*, 34 F.P.C., at 193, and *Southern Louisiana*, Opinion 546, mimeo., 28."
60	24	Insert "Opinion 546" after "*Louisiana*"; insert comma after "mimeo."; delete "page"
74	10	Change first comma to a semicolon
79	6	Insert a comma after "*Louisiana*"; change "(mimeo., 72)" to "mimeo., 72,"
85	23	Insert "Opinion 546," after "*Southern Louisiana*,"; change "pages" to a comma
99	37	Change "Southern" to "southern"
117	line 3 of table	Change "North" to "Northern"
	line 5 of table	Change "North" to "Northern"
	line 6 of table	Change "South" to "Southern"
121	last line of table	Insert "Northwest" before "Alabama"
121	second line of footnote	Insert "Northwest" before "Alabama"
123	last line of table	Insert "Northwest" before "Alabama"
123	second line of footnote	Insert "Northwest" before "Alabama"
124	28	Delete "at"

Errata Notice

[11,514]

Page	Line	Correction
125	18	Insert a comma after "mimeo."
126	1	Change "at" to "mimeo.,"
128	7	Delete "at"
	8	Delete "at"
	15	Delete "at"
	28	Delete "at"
133	10	One space only after "*Ibid.*"

/s/ Howell Purdue
HOWELL PURDUE
Presiding Examiner

[12,083]

Opinion and Order

[12,083]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

OPINION NO. 607

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

OPINION AND ORDER DETERMINING JUST AND REASONABLE RATES FOR NATURAL GAS PRODUCED IN THE OTHER SOUTHWEST AREA

Issued: October 29, 1971

DC-52

Opinion and Order

[12,084]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

OPINION NO. 607

APPEARANCES

Edwin S. Nail for Amerada Petroleum Corporation.

Charles F. Wheatley, Jr. for American Public Gas Association.

Robert Roberts, Jr., Blanchard, Walker, O'Quin & Roberts, Bernard A. Foster, Jr., Ross, Marsh & Foster for Arkansas Louisiana Gas Company.

J. N. Clayton, Bernard A. Foster, Jr., Ross, Marsh & Foster for Arkla Exploration Company.

Ted Holshouser for Ashland Oil & Refining Company.

John E. Holtzinger, Jr., Frederick Moring and *J. David Mann, Jr., Morgan, Lewis & Bockius* for Associated Gas Distributors Group, consisting of Atlanta Gas Light Company; The Berkshire Gas Company; Boston Gas Company; Bristol and Warren Gas Company; Brockton Taunton Gas Company; Buzzards Bay Gas Company; Cambridge Gas Company; Central Massachusetts Gas Company; City of Holyoke, Massachusetts Gas and Electric Department; City of Norwich, Department of Public Utilities; City of Westfield Gas and Electric Light Department; Concord Natural Gas Corporation; The Connecticut Gas Company; Fall River

Gas Company; Fitchburg Gas and Electric Light Company; Gas Service, Inc.; The Greenwich Gas Company; The Hartford Electric Light Company; The Hartford Gas Company; Haverhill Gas Company; Lawrence Gas Company; Lowell Gas Company; Lynn Gas Company; Manchester Gas Company; Mystic Valley Gas Company; New Bedford Gas and Edison Light Company; The New Britain Gas Light Company; The Newport Gas Light Company; Northampton Gas Light Company; North Attleboro Gas Company; North Shore Gas Company; Norwood Gas Company; The Pequot Gas Company; Providence Gas Company; South County Gas Company; The Southern Connecticut Gas Company; Springfield Gas Light Company; Tiverton Gas Company; Valley Gas Company; Wachusett Gas Company; Worcester Gas Light Company; Brooklyn

Union Gas Company; Central Hudson Gas and Electric Corporation; Consolidated Edison Company of New York, Inc.; The East Ohio Gas Company; Consolidated Gas Supply Corporation; Lake Shore Pipeline Company; The Peoples Natural Gas Company; The River Gas Company; Elizabethtown Gas Company; Long Island Lighting Company; New Jersey Natural Gas Company; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation; Orange and Rockland Utilities, Inc.; Philadelphia Electric Company; Philadelphia Gas Works, Division of UGI Corporation; Piedmont Natural Gas Company, Inc.; Public Service Company of North Carolina; Public Service Electric and Gas Company; Rochester Gas and Electric Corporation; South Jersey Gas Company; UGI Corporation; and Washington Gas Light Company.

Opinion and Order

Stuart J. Scott, Robert E. Wade, Bernard A. Foster, Jr., Ross, Marsh & Foster for Atlantic Richfield Company.

J. Evans Attwell, Vinson, Elkins, Weems & Searls for Austral Oil Company, Inc., Alfred C. Glassell, Jr., *et al.*, George Mitchell & Associates, Inc., Richardson Oils, Inc., Robert Mosbacher, J. Hughes Dudley and A. C. Glassell.

John W. Glendening, Jr. and *John S. Schmid, Glendening and Schmid* for The Berkshire Gas Company; Boston Gas Company; Bristol and Warren Gas Company; Brockton Taunton Gas Company; Buzzards Bay Gas Company; Cambridge Gas Company; Central Massachusetts Gas Company; City of Holyoke, Massachusetts Gas and Electric Department; City of Norwich, Department of Public Utilities; City of Westfield Gas and Electric Light Department; Concord Natural Gas Corporation; The Connecticut Gas Company; Fall River Gas Company; Fitchburg Gas and Electric Light Company; Gas Service, Inc.; The Greenwich Gas Company; The Hartford Electric Light Company; The Hartford Gas Company; Haverhill Gas Company; Lawrence Gas Company; Lowell Gas Company; Lynn Gas Company; Manchester Gas Company; Mystic Valley Gas Company; New Bedford Gas and Edison Light Company; The New Britain Gas Light Company; The Newport Gas Light Company; Northampton Gas Light Company; North Attleboro Gas Company; North Shore Gas Company; Norwood Gas Company; The Pequot Gas Company; Providence Gas Company; South County Gas Company; The Southern Connecticut Gas Company; Springfield Gas Light Company; Tiverton Gas Company; Valley Gas Company; Wachusett Gas Company; Worcester Gas Light Company.

[12,085]

Opinion and Order

Edwin F. Russell, Jr. and *Barbara M. Suchow, Cullen and Dykman* for The Brooklyn Union Gas Company.

Mary Moran Pajalich, J. Calvin Simpson and *Sheldon Rosenthal* for The People of the State of California and The Public Utilities Commission of California.

[12,086]

Woolen H. Walshe, Justin R. Wolf and *Eugene E. Threadgill, Wolf & Case* for The California Company, a Division of Chevron Oil Company.

Gould & Wilkie for Central Hudson Gas & Electric Corporation.

Mathias M. Mattern for the City of Chicago.

Cecil C. Cammack, Graydon D. Luthey, and *R. J. Leithead* for Cities Service Oil Company, Cities Service Company, and Columbian Fuel Corporation.

Charles S. Rhyne, Rhyne & Rhyne for City Group Gas Defense Association, consisting of the Kansas Cities of Altamont, Atchison, Chanute, Countryside, Erie, Fairway, Girard, Grenola, Howard, Iola, Leavenworth, Neodesha, and Prairie Village; and the Missouri Cities of Aurora, Carl Junction, Carthage, Independence, Joplin, Kansas City, Marshall, Monett, Mt. Vernon, Neosho, Nevada, Oronogo, St. Joseph, Springfield, Waverly, and Webb City.

Halcyon G. Skinner and *Lex K. Larson, LeBoeuf, Lamb, Leiby & Mac Rae* for Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation, and Orange and Rockland Utilities, Inc.

K. M. Waters, Jr., C. William Cooper, H. B. Griffith, Jr., Lawrence L. Gray, Norman A. Flaningam, Henry A. Jackson, Thomas G. Roderick and *Thomas A. White* for Consolidated Gas Supply Corporation.

Bruce R. Merrill, Joseph C. Johnson and *Thomas H. Burton* for Continental Oil Company.

Edward Kliewer, Jr., for Delta Drilling Company, Elizabeth F. Dorfman Trust, Louis Dorfman, Sam Y. Dorfman, Jr. and S. L. Florsheim.

J. G. Eckel, Bernard A. Foster, Jr., Ross, Marsh & Foster for Dorchester Gas Producing Company.

C. William Cooper, H. B. Griffith, Jr., Lawrence L. Gray, Norman A. Flaningam, Henry A. Jackson, Thomas G. Roderick and *Thomas A. White* for The East Ohio Gas Company, The River Gas Company, Lake Shore Pipeline, Co., and The Peoples Natural Gas Company.

G. Scott Cuming, Walter G. Henderson, C. Frank Reifsnyder and *Stanley S. Harris, Hogan & Hartson* for El Paso Natural Gas Company.

[12,087]

John R. Sailer for Elizabethtown Gas Company.

John L. Arrington, Jr., Lupardus, Holliman and Huffman for Falcon Seaboard Drilling Company.

C. R. Eyster and *Richard F. Generelly* for Forest Oil Corporation.

Warren M. Sparks and *Donald R. Arnett* for Gulf Oil Corporation and Warren Petroleum Corporation.

Blake Hamman in propria persona.

Richard F. Generelly, May, Shannon and Morley for H. L. Hawkins & H. L. Hawkins, Jr., Houston Royalty Company and Norton Oil Company, Inc.

Douglas J. Miles for Humble Gas Transmission Company.

Martin N. Erck, Frank S. Troidl, Robert L. Norris, Jr., and *J. Kirby Ellis* for Humble Oil & Refining Company.

Opinion and Order

Robert W. Henderson, Paul W. Hicks and *Donald K. Young* for Hunt Oil Company, H. L. Hunt, Haroldson L. Hunt, Jr., Trust Estate, Hassie Hunt Trust, Hunt Industries, Lamar Hunt, Lamar Hunt Trust Estate, Nelson Bunker Hunt Trust Estate, Hunt Petroleum Corporation, William Herbert Hunt Trust Estate, and Placid Oil Company.

L. Dan Jones and *Williams I. Powell* for Independent Petroleum Association of America.

John F. Gaston for Iowa Electric Light and Power Company.

Bertram D. Moll for Long Island Lighting Company.

Robert W. Russell for the City of Los Angeles.

H. E. McCommons in propria persona.

Bernard A. Foster, Jr., Ross, Marsh & Foster for Magna Oil Corporation, and J. C. Trahan, Drilling Contractor, Inc.

Jack Fariss for Marathon Oil Company.

F. W. Reese for M. H. Marr.

Richard M. Merriman and *Peyton G. Bowman, III, Reid and Priest* for Michigan Gas Utilities Company.

[12,088]

David P. Van Note for Michigan Public Service Commission.

Charles V. Shannon, May, Shannon and Morley and *Paul S. Davis* for Michigan Wisconsin Pipe Line Company.

John F. Brown for Mississippi River Transmission Corporation.

Charles B. Swanner, R. D. Haworth, Charles S. Chester and *James L. Armour* for Mobil Oil Corporation.

Richard F. Generelly for Monsanto Company.

E. H. Hasenberg for Natural Gas Pipeline Company of America.

Kent H. Brown and *Morton L. Simons* for The Public Service Commission of the State of New York.

Harry L. Bristol, Naylor, Aronson, Huber & Magill for New York State Electric & Gas Corporation.

Lauman Martin for Niagara Mohawk Power Corporation.

George W. Ryerson for Northern Illinois Gas Company.

Edmund A. Schroer and *Joseph T. Morrow, Lawyer, Schroer & Eichhorn* for Northern Indiana Public Service Company.

Lewis G. Mosburg, Jr., Mosteller, Andrews & Mosburg for Oklahoma Independent Petroleum Association.

John L. Arrington, Jr., Lupardus, Holliman and Huffman for Oklahoma Natural Gas Company.

Frederick T. Searls, Malcolm H. Furbush and *Stanley T. Skinner* for Pacific Gas and Electric Company.

John Ormasa, Eric W. Martens, William H. Owens, R. D. Twomey, Jr., and *K. R. Edsall* for Pacific Lighting Service and Supply Company.

J. P. Hammond and *William H. Emerson* for Pan American Petroleum Corporation.

W. P. Anderson for Panhandle Eastern Pipe Line Company.

Herbert E. Squires for Pennsylvania Public Utility Commission.

Samuel G. Miller, Henry P. Sullivan and *Donald Blanken* for Philadelphia Electric Company.

[12,089]

William T. Coleman, Jr. and *Robert W. Maris, Dilworth, Paxson. Kalish, Kohn & Levy* for Philadelphia Gas Works, Division of The United Gas Improvement Company.

Kenneth Heady and *John R. Rebman* for Phillips Petroleum Company.

James V. Landress for W. L. Pickens.

Stanley M. Morley, May, Shannon and Morley for Pipeline Purchaser Group, consisting of Southern Natural Gas Company, Texas Eastern Transmission Corporation, United Gas Pipe Line Company, Natural Gas Pipeline Company of America, Tennessee Gas Pipeline Company, Texas Gas Transmission Corporation, Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Cities Service Gas Company, and Lone Star Gas Company.

J. Harry Mulhern, Edward S. Kirby and *James R. Lacey* for Public Service Electric and Gas Company.

Norman P. Hines, Jr. for Reserve Oil and Gas Company.

Lynn R. Coleman for Richardson Oils, Inc.

Richard N. George, Nixon, Hargrave, Devans & Doyle for Rochester Gas and Electric Corporation.

Sherman Chickering, C. Hayden Ames and *Donald J. Richardson, Jr., Chickering & Gregory* for San Diego Gas & Electric Company.

Gene P. Morrell for Samedan Oil Corporation.

James D. McKinney, Jr., Ross, Marsh and Foster for Service Gas Products Company.

Oliver L. Stone, Thomas G. Johnson and *Dan A. Bruce* for Shell Oil Company.

A. E. Stebbings, Michael P. Kelly, Bradford Ross and *James D. McKinney, Jr., Ross, Marsh & Foster* for Signal Oil and Gas Company and Service Gas Products Company.

Rex Short, Charles E. McGee, John T. Ketcham and *Charles E. Holmes* for Sinclair Oil Corporation.

John Ormasa, Eric W. Martens, R. D. Twomey, Jr., and *K. R. Edsall* for Southern California Gas Company and Southern Counties Gas Company of California.

Hugh J. Morgan, Jr. for Southern Natural Gas Company.

[12,090]

Robert C. Koury, Cole, Koury, Cole and Tighe for South Jersey Gas Company.

T. A. McEachern, Jr., for Southwest Gas Producing Company, Inc.

Claude Proctor, Justin R. Wolf and *Eugene E. Threadgill, Wolf & Case* for Standard Oil Company of Texas, a Division of Chevron Oil Company.

Phillip D. Endom, Francis H. Caskin, May, Shannon and Morley for Sun Oil Company.

Homer E. McEwen, Jr. for Sunray DX Oil Company.

H. W. Varner and *William T. Kilbourne* for The Superior Oil Company.

William K. Tell, Jr., William R. Slye and *James D. Annett* for Texaco Inc.

[12,090]

Opinion and Order

Crawford C. Martin, C. Daniel Jones, Jr. and *Linward Shivers* for The State of Texas and the Railroad Commission of Texas.

John Davenport for Texas Independent Producers & Royalty Owners Association.

Raymond N. Shibley and *William J. LeBuhn, Patterson, Belknap, Farmer, Shibley & Wells* for Trunkline Gas Company.

George C. Bond for Union Oil Company of California.

Thomas Fletcher for Union Producing Company.

Elliot G. Flowers, Justin R. Wolf and *Eugene E. Threadgill, Wolf & Case* for Union Texas Petroleum, a Division of Allied Chemical Corporation.

J. David Mann, Jr. and *John E. Holtzinger, Jr., Morgan, Lewis & Bockius* for The United Gas Improvement Company.

Saunders Gregg for United Gas Pipe Line Company.

Paul E. Reichardt for Washington Gas Light Company.

George J. Eckert for Westates Petroleum Company.

Thomas M. Knebel, Rea, Cross & Knebel for Willmut Gas and Oil Company.

[12,091]

William E. Torkelson for Public Service Commission of Wisconsin

Reuben Lozner, Robert W. Perdue, Walter J. Kendall, III, Richard V. Mattingly, Jr., and *Robert A. Jablon* for the staff of the Federal Power Commission.

[12,092]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: John N. Nassikas, Chairman; John A. Carver, Jr., Albert B. Brooke, Jr. and Pinkey Walker.

Docket Nos. AR67-1,*et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

OPINION NO. 607

OPINION AND ORDER DETERMINING JUST AND REASONABLE RATES FOR NATURAL GAS PRODUCED IN THE OTHER SOUTHWEST AREA

(Issued October 29, 1971)

BROOKE, Commissioner:

1. By order issued February 28, 1967, 37 FPC 400, the Commission instituted this proceeding to determine just and reasonable rates for jurisdictional sales of natural gas by independent producers in what was designated the "Other Southwest Area". This area includes the States of Arkansas and Mississippi and portions of four other states, Texas Railroad Commission Districts Nos. 5, 6 and 9, four counties in northwest Alabama, 56 counties in southern and eastern Oklahoma, and all of Louisiana north of the 31° parallel.[1] The underwater lands on

[1] The Oklahoma counties, hereafter referred to as "Other Oklahoma," are all those not included in the Hugoton-Anadarko Area Rate Proceeding. The portion of Louisiana included in this proceeding is the part not included in the Southern Louisiana Area Rate Proceeding.

the continental shelf off the shore of Mississippi were included by Commission order

[12,093]

issued December 8, 1967, 38 FPC 1135.

2. In order to prevent duplication, the original order of February 28, 1967, directed the Examiner to incorporate by reference all the evidence in *Texas Gulf Coast*[2] and *Hugoton-Anadarko*[3] area rate proceedings and allowed for the incorporation of evidence by reference from the *Permian*[4] and *Southern Louisiana*[5] area rate proceedings.

3. Presiding Examiner Howell Purdue's initial decision was issued September 22, 1969. Exceptions were filed by participants listed in Appendix A to this Opinion and Order, and oral argument was held before the Commission on May 27, 1970.

The Area

4. "Other Southwest" is not a homogeneous area. Each of the four areas covered by previous area rate proceedings was generally similar throughout, with some deviations, in geology, pricing history and markets served by the gas

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[2] Opinion No. 595, issued May 6, 1971, Docket Nos. AR64-2, *et al.*

[3] Opinion No. 586, issued September 18, 1970, Docket Nos. AR64-1, *et al.*, appeal pending, CA9, No. 71-1036.

[4] 40 FPC 30 (1968), modified 41 FPC 301 (1969), aff'd 428 F.2d 407 (CA5, 1970), *cert. den.* 400 U.S. 950 (1970).

[5] Opinion No. 598, —— FPC —— (1971), appeal pending *sub nom. Placid Oil Company, et al.*

produced in the area concerned. Other Southwest, on the other hand, has a variety of pricing histories in its different sub-areas, the geology varies in different sub-areas,[6] and the gas produced in Texas District 9, Other Oklahoma and northwestern Arkansas goes to different markets than gas produced in other sub-areas. The importance of the intrastate market varies in the various sub-areas.[7] The age of development

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[6] The geology of the area is described in detail in the initial decision, pages 10-12. In general, the Ouachita fault, running from southwest to northeast, divides Texas District 9, Oklahoma and northwestern Arkansas from Texas District 6, northern Louisiana, southern Arkansas, the four Alabama counties and Mississippi. Texas District 5 straddles the fault.

[7] Reports (Form 15) filed by pipelines with the Commission indicate jurisdictional sales of 1.210 trillion cubic feet in 1969, or 56.2 percent of the 2.152 trillion feet of production reported by the American Gas Association (AGA) for 1969 in the Other Southwest Area.

See Appendix B. By sub-areas, the comparable figures in billions of cubic feet are:

	AGA Production	Form 15 Sales	Percentage
Other Oklahoma	592	260	44
Texas R.R. Dist. 9	181	60	33
Arkansas	166	138	83
Texas R.R. Dist. 6	437	217	50
Northern Louisiana	488	410	84
Mississippi	166	125	75

All sales in Texas R.R. District 5 were intrastate in 1969, although there have been some interstate sales this year. No statistics are available for Alabama, but the volume is very small. The percentages are subject to a slight distortion because AGA production includes gas used in the field and never sold.

and the potential for future development also differ widely throughout the Other Southwest area. For these reasons, we shall consider the various sub-areas separately, stating in each instance the facts relevant to our particular determination.

Initial Decision

5. The initial decision fixed the following base area rates in cents per Mcf,[a]:

	Gas-Well Gas Under Contracts Dated Before 1961, and All Casinghead Gas	Gas-Well Gas Under Contracts Dated After 1960	Deduction if Gathering Not Performed
Other Oklahoma	17.5	18.4	1.5
Texas District 9	17.8	18.7	1.5
Northern Arkansas	17.0	17.8	1.5
Texas District 5 & 6	14.1	18.1	1.0
Northern Louisiana	15.8	19.6	1.0
Southern Arkansas	13.5	17.25	1.0
Mississippi [b] and Northwest Alabama	16.75	18.25	1.25

[a] Rates are at 14.65 psia except for northern Louisiana, Mississippi and Northern Alabama, where rates are at 15.025 psia.

[b] No rate was fixed for the Federal domain offshore Mississippi, where as yet there is no production.

6. Quality and pressure standards were adopted. The base area rate for gas not meeting a particular standard was to be adjusted in the same manner as in previous area rate cases.

The maximum and minimum Btu contents in Btu's per cubic foot, were:

	Maximum	Minimum
Other Oklahoma, Texas District 9 and Northern Arkansas	1060	1000
Texas Districts 5 and 6, Northern Louisiana and Southern Arkansas	1030	1000
Mississippi and Alabama	990	950

7. Moratoriums were established on filing rate increases; refunds were required in Section 4(e) proceedings where collected rates exceeded the applicable area rates; and small producers were exempted from making quality adjustments.

Summary of Commission Decision

8. Our basic rate determinations here may be summarized as follows:

Base Rates Until July 1, 1974 for Gathered Gas a/
(in cents per Mcf at 14.65 psia unless otherwise indicated)

	Contracts Dated Prior to 1-1-61				Contracts Dated 1-1-61 to 10-1-68				Contracts Dated After 10-1-68		Deduction If Gas Ungathered	Standard for Adjustment for Btu Content	
	Prior to 1-1-65	1-1-65 Through 9-30-68	10-1-68 Through 9-30-73	From 10-1-73	Prior to 1-1-65	1-1-65 Through 10-1-68	10-1-68 Through 9-30-73	From 10-1-73	10-1-68 Through 9-30-73	From 10-1-73		Maximum	Minimum
Other Oklahoma	17.5	18.4	19.4	20.4	18.4	18.9	19.4	20.4	23.75	24.75	1.5	1060	1000
Texas RR District No. 9	17.8	18.7	19.7	20.7	18.7	19.2	19.7	20.7	24.0	25.0	1.5	1060	1000
Northern Arkansas	17.0	17.9	18.8	19.8	17.8	18.3	18.8	19.8	23.0	24.0	1.5	1060	1000
Texas RR District No. 5	-	-	-	-	-	-	-	-	23.5	24.5		1030	1000
Texas RR District No. 6	15.0	17.0	19.1	20.1	18.1	18.6	19.1	20.1	23.5	24.5	1.0	1030	1000
Northern Louisiana b/	16.7	18.6	20.6	21.6	19.6	20.1	20.6	21.6	25.0	26.0	1.0	1030	1000
Southern Arkansas	14.4	16.25	18.25	19.25	17.25	17.75	18.25	19.25	22.5	23.5	1.0	1030	1000
Mississippi-Alabama b/	19.0	19.5	20.0	21.0	19.0	19.50	20.0	21.0	25.0	26.0	1.25	990	950
Federal Domain b/ (offshore of Mississippi)	-	-	-	-	-		-		26.0	g/		1050	1000

a/ "Gathered" gas, as used in this opinion, refers to gas delivered at a central point, the tailgate of a plant, or a point on the buyer's pipeline.

b/ At 15.025 psia.

g/ The price will increase from 26 to 27 cents on October 1, 1974, rather than October 1, 1973.

Supply and Demand

9. We need not repeat in this opinion discussions of the nationwide situation with respect to the supply and demand for natural gas which are set forth in our recent opinions in *Texas Gulf Coast Area Rate Proceeding*, Opinion No. 595, 45 FPC ——, mimeo pages 11-12, paragraphs 30-32 (1971) and *Southern Louisiana Area Rate Proceeding*, Opinion No. 598 (Southern Louisiana II), 46 FPC ——, mimeo pages 19, 23, 31-32, paragraphs 40, 51-2, 65-68 (1971), appeal pending *sub nom. Placid Oil Company, et al.* v. *F.P.C.* (CA5, No. 71-2761). Therefore, we incorporate by reference our discussion in those opinions.

10. In the Other Southwest Area, as in the Texas Gulf Coast, the gas supply situation is worse than in the national as a whole. Purchases and production by interstate pipelines have increased from 9.6 trillion cubic feet of gas nationally in 1963 to 13.7 trillion in 1969.[8] During the same period, purchases and production by interstate pipelines in the Other Southwest area have remained almost constant at slightly over 1.2 trillion cubic feet per year. Gas purchases and production by interstate pipelines in the Other Southwest area have declined from 13 percent of such purchases in the nation as a whole in 1963

[8] We take official notice of purchase, production, reserves, gas findings and cost data which have become available since the conclusion of the hearing. The sources of such data include those set forth in Exhibit B and those cited in *Texas Gulf Coast, supra*, and *Southern Louisiana II, supra*.

to 9 percent in 1969.[9] Further, the ratio of reserves to production for interstate pipelines in the area has declined from 11.0 in 1964 to 9.8 in 1969,[10] and the findings to production ratio has been below unity since 1965.[11] Less than 12 percent of the production of gas for interstate commerce in 1969 came from new reservoirs which commenced production in the six-year period 1964-1969. We find that new dedications to the interstate market from the Other Southwest area have not been sufficient to replace rapidly depleting reserves and that production for interstate commerce has not made an adequate contribution toward satisfying the accelerating nationwide demand for natural gas. There appears to be no question that the demand for gas from this area will not only absorb all the area can supply, but that the expanding interstate market would absorb far more gas than can be expected to be available. The reserves in some parts of the area are being gradually depleted without any real expectation of sufficient new findings to replace them. While

[12,100]

we cannot expect that this area will be able to supply the potential demand upon it, it is important that its potential be fully utilized in this time of national need for all available gas.[12]

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[9] The Gas Supplies of Interstate Natural Gas Pipeline Companies, 1969, FPC S-206, Table 13, at page 33.

[10] Ibid.

[11] See Appendix B.

[12] E.g. Ex. 51, page 21 and Tr. 960-73 indicate potential for additional reserves in Mississippi and Northern Louisiana.

11. For the five years, 1966-1970, the Other Southwest production of gas for interstate commerce was 6.035 trillion cubic feet and the additions to reserves dedicated to interstate commerce were 3.225 trillion cubic feet. (See Appendix B.) While annual production was consistently about 1.2 trillion cubic feet, additions to reserves varied widely, and were very small in the last three years of the period. New findings in this period were even smaller than reserve additions, as the latter includes extensions and revisions of prior estimates (usually upward) as well as findings. If production continues steady for the next five years, more than six trillion cubic feet in new dedications to interstate commerce will be needed simply to offset depletion of interstate reserves. It is obvious that at least this level of new dedications must be attained if production from the area is not to be curtailed.

[12,101]

To equal both interstate and intrastate production for the last five years, new findings would have to approximate 11 trillion cubic feet. It is questionable whether this can be achieved. To enable the area to supply its present share of the national interstate market in view of the constantly increasing demand, the level of new discoveries must be even higher.

12. We find that it is not possible to set realistic goals for new dedications of gas from Other Southwest to the interstate market. This area is unlike Texas Gulf Coast and Southern Louisiana, where there is the still largely untapped offshore potential, the industry is actively engaged in exploration and development, successful drilling is rewarded by large new reservoirs, many major pipelines are immediately available as purchasers, and gas

may readily be sold at the prices allowed by this Commission. In other Southwest, by comparison, the major producers have decreased their activity as they seek more rewarding prospects elsewhere. Recent discoveries are smaller in size, and sometimes located relatively far from interstate pipelines.

13. There is no reliable evidence to indicate the amount of new gas reserves that would be discovered as the

[12,102]

result of any specific change in rates, nor evidence as to the amount of such reserves that would be dedicated to the interstate market. We estimate that this area has probable reserves of from 15 to 18 trillion cubic feet still to be discovered.[13] The prices established herein provide incentives, however, to the producers in this marginal area to find gas and dedicate it to interstate commerce. The prices established will enable the interstate market to compete in price with the present and potential intrastate buyers in the area.

14. With respect to supply and demand, the United States Court of Appeals for the Fifth Circuit has indicated we should estimate the demand for gas, the desired level of service, and how the rate set will achieve that level. *Southern Louisiana I*, 428 F.2d at 44. Such a task is most difficult where as here, 40 to 45 percent of the gas production goes to the intrastate market.[14] Moreover, we know that the demand for gas is increasing faster than reserves are being added. As we indicated earlier,

[13] This estimate is believed to be conservative. It is based upon the statistics of the Potential Gas Committee, although the areas into which the country is divided by the Committee do not coincide with those used by us in area rate proceedings.

[14] See Appendix B; also footnote 7, page 3, *supra*.

11 trillion cubic feet in new reserve additions in the Other Southwest will be required over the next five years to meet the present level of demand of the intrastate market and to continue the current level of jurisdictional sales. We cannot call this a desired level of service, but only a forecast based on present sales. We can state, however, that the rates provided in our order should have a positive impact upon exploration for and development of gas supplies from this area.

15. The court also indicated that we should make findings as to the consequences of our order upon the industry. At the outset, we can state that the rate design contained herein should encourage new exploration and development in the Other Southwest area and dedications to the interstate market of gas that becomes available. With respect to the capital requirements of the industry, we adopt our findings in Opinion No. 598, at pages 39-45. We are acutely mindful of the continued decline in capital formation at the same time industry requirements are increasing. We find, contrary to the initial decision, that the attractiveness of the many alternative investment possibilities must be considered in providing inducements to the necessary capital investment to the end that the continuing decline in exploration for and development of gas reserves in this area may be reduced.

[12,104]

Further Points of Reference in Determining Rates

16. In determining the rates to be established in the various sub-areas we will consider not only the various cost computations, but also the levels of interstate prices in each sub-area, the levels of the unregulated intrastate

price in each sub-area, the levels of prices in adjacent areas where the Commission has established area rates, the varying pricing history and quality conditions in each such area as compared with the particular Other Southwest sub-area. The cost computations considered in establishing the price of the latest vintage of gas are nationally oriented and based in large part upon published data. We need not repeat our recent discussions of new gas costing set forth in *Southern Louisiana II* and *Texas Gulf Coast.* The principles there set forth are equally applicable here, and reference may be had to those opinions.[15]

[12,105]

Rates in Other Southwest State Domains For Gas Under Contracts Dated On Or After October 1, 1968

17. We herein establish October 1, 1968, as the date of division between the latest vintage of gas and earlier vintages. This is done to avoid multiplicity in division dates in the different producing areas and is in accordance with our reasoning in *Texas Gulf Coast, supra; Southern Louisiana II, supra;* see also *Hugoton-Anadarko Area Rate Proceeding,* Opinion No. 586, —— FPC —— (1971), presently on appeal.

18. In *Texas Gulf Coast* the price for gas under contracts dated on or after October 1, 1968, was fixed at

[15] Substantial changes have occurred since the initial decision computed the new gas-well gas cost of 16.22 cents per Mcf. That decision was based on 1963 Census data for drilling costs per foot and dry hole costs per foot. The 1967 Census data indicates a substantial increase in these costs. The Examiner found that a 10.5 percent rate of return was appropriate, whereas in Opinion Nos. 595 and 598, we indicated that a rate of return of approximately 15 percent was reasonable.

24 cents per Mcf after consideration of the prices paid for intrastate sales, which absorb the great majority of the gas in the Texas Gulf Coast area, the contract prices for interstate sales, and a cost range of 22 to 26 cents per Mcf when .4 cent was included for delivery to a central point in the field, the tailgate of a plant, or a point on the buyer's pipeline.

[12,106]

19. While the intrastate market does not dominate the Other Southwest area to the extent that it dominates the Texas Gulf Coast, there is a very substantial intrastate market in Other Oklahoma and Texas Districts 9, 5, and 6.[16] Examination of the prices in the area, summarized in Appendix C, reveals that neither the interstate nor intrastate prices have reached the Texas Gulf Coast level in any of the sub-areas. The in-line price of 15 cents per Mcf in Other Oklahoma is below the in-line prices of 16 and 17 cents in the Texas Gulf Coast. The upper guideline rates of 15 cents in Other Oklahoma and Texas District 6 and 14.5 cents in Texas Districts 5 and 9 are also below the 16 and 17-cent upper guidelines in Texas Gulf Coast, while the 18.75-cent (including taxes) upper guideline in northern Louisiana and the 21.5-cent upper guideline in Mississippi are well above the Texas Gulf Coast level. The average quality of gas in the Other Southwest is inferior, either in Btu content, pressure, or purity, to that produced in the Texas Gulf Coast.

[12,107]

20. In the Hugoton-Anadarko area which bounds Other Southwest to the northwest, we found just and reason-

[16] See footnote 7, page 3, *supra*.

able a price of 20.5 cents per Mcf for Texas gas under the latest contracts delivered after substantial gathering at a central point or the tailgate of a plant.

21. *In Southern Louisiana II*, we approved as just and reasonable a price of 26 cents per Mcf (for gas delivered at a central point) submitted in a settlement proposal supported by the great majority of the participants. This price, allowing for the different state taxes and pressure base, was within the cost range found in *Texas Gulf Coast* as well as justified by the cost conclusions reached in *Southern Louisiana II* after consideration of additional evidence not available in *Texas Gulf Coast*. The intrastate market in Southern Louisiana, although much smaller than the interstate market, has reached even higher price levels than in Texas Gulf Coast, and considerably above those in Other Southwest. Guideline and in-line prices in Southern Louisiana, as well as historical price patterns, have exceeded those in Other Southwest sub-areas by substantial amounts, except in Mississippi. In Mississippi, the upper guideline rate was 21.5 cents as compared with Southern Louisiana's 21.25 cents, and the in-line price was 20.6 cents as compared with Southern Louisiana's 20 cents. The average quality of

[12,108]

Southern Louisiana gas is much better than the average quality of gas anywhere in Other Southwest. Despite the slightly higher guideline and in-line rates prevailing in Mississippi, the contract rates, at least after 1961, appear to have been lower than in Southern Louisiana. Mississippi and Alabama gas has a lower average Btu content than does Southern Louisiana gas or gas from any other part of the Other Southwest. Geologically, onshore Mississippi and Alabama are similar to the northern part of Louisiana rather than the southern.

22. We have also considered the necessity for providing a proper incentive to producers to explore for gas in this area and dedicate it to interstate commerce. Unless the area is to be abandoned, producers must be able to obtain rewards comparable with those in other areas.

23. Having considered all of the foregoing as well as the differing state taxes and pressure bases,[17] we find the just and reasonable base area rates for gas under contracts dated on or after October 1, 1968,

[12,109]

delivered at a central point, the tailgate of a plant, or a point on the buyer's pipeline to be, in cents per Mcf:

Texas District 9	24
Northern Arkansas	23
Other Oklahoma	23.75
Texas Districts 5 and 6	23.5
Southern Arkansas	22.5
Northern Louisiana	25
Mississippi and Alabama [18]	25

24. As provided in *Texas Gulf Coast* at page 40, and for the reasons there stated, all the foregoing rates will escalate one cent on October 1, 1973.

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[17] 14.65 psia except in Louisiana, Mississippi and Alabama, where it is 15.025 psia.

[18] Producer Witness Foster and Staff Witness Engel recommended that all Mississippi be treated as a whole, and that the four Alabama counties be included with Mississippi. The initial decision so provided (page 92). Witness Foster also recommended including five northern Louisiana parishes with Mississippi instead of with the rest of northern Louisiana. The initial decision, however, aligned the five parishes with the rest of northern Louisiana, as recommended by Witness Engel (pages 93-5). We concur in both the Examiner's conclusions.

[12,110]

Rate in the Federal Domain Offshore of Mississippi

25. The initial decision fixed no area rate applicable to the Federal domain offshore Mississippi on the ground that there was no production from the offshore area and, therefore, neither price patterns nor marketing patterns. Witness Engel suggested that possibly offshore Mississippi should await the Commission's decision with respect to offshore Louisiana, and be handled in the same manner. (Tr. 4520). The initial decision points out that offshore Mississippi is very small compared to adjacent offshore Louisiana, and is in the same geological province. The uncontradicted testimony is that there is no reason to believe that structures similar to those found off Louisiana will not be found off Mississippi. Witness Durst, Tr. 783; initial decision, page 93.

[12,111]

26. We find it in the public interest that an applicable area rate should be established for the Federal domain offshore Mississippi so that plans for exploration and development may be made with knowledge of the prices to be expected. We find that the Federal domain offshore Mississippi rate should be the same as that for the Federal domain offshore Louisiana, in view of the similar geology and drilling conditions, as well as the absence of any cost or pricing history peculiar to offshore Mississippi. The rate we prescribe (at 15.025 psia) is 26 cents per Mcf for gas delivered at a central point in the field, the tailgate of a plant or a point on the buyer's pipeline.

27. Because of the previously indicated relationship between the areas, the same periodic escalation in the base

area rate for third vintage gas will be permitted in the Federal domain offshore of Mississippi as in the Federal domain offshore of southern Louisiana : one cent per Mcf on October 1, 1974. The reasons for this escalation were set forth in Opinion No. 598 and need not be repeated here.

[12,112]

Rates in Mississippi and Alabama for Gas Under Contracts Dated Before October 1, 1968

28. The comparison of the average prices paid by interstate pipelines for jurisdictional and interstate gas in 1960 with the initial decision's cost-based prices for pre-1961 gathered gas in Mississippi and Alabama is as follows, in cents per Mcf: [19]

Jurisdictional Prices	Intrastate Prices	Initial Decision
20.81	14.65	16.75

In the adjacent Southern Louisiana area a rate of 20.625 cents per Mcf has been established for gas of this vintage for the period prior to January 1, 1965, and a rate of 21.25 cents per Mcf from January 1, 1965, through September 30, 1968.[20] The price of gas of this vintage after August 1, 1971 became 22.375 cents per Mcf in Southern Louisiana, which (adjusted for the difference in state taxes, but not for differing quality, location or market factors) is equivalent to 21.37 cents in Mississippi and Alabama.

[19] Ex. 60, Sch. 7, Sheet 3. (All prices are at 15.025 psia.)

[20] Adjusted for the difference in state taxes equivalent rates in Mississippi and Alabama would be approximately one cent per Mcf lower.

[12,113]

29. If our prices for the pre-1965 period were to be based upon the cost computations in the initial decision, as were those in *Texas Gulf Cost*, the prices indicated for Mississippi and Alabama for the period prior to 1965 would be approximately 18 cents for pre-1961 gathered gas and 18.25 cents for gathered gas under contracts dated from January 1, 1961 through September 30, 1968. Jurisdictional market prices were somewhat higher and the prices established in adjacent Southern Louisiana higher still. We find upon consideration of all of these factors the just and reasonable rate for gathered gas in Mississippi and Alabama prior to 1965 is 19 cents per Mcf. We find that there is no reason to establish different vintages of gas for sales under contracts dated prior to October 1, 1968. We find also that an escalation of .5 cent in the price of such gas should take place on January 1, 1965, and an additional escalation of .5 cent should take place on October 1, 1968, in accordance with our determination in *Texas Gulf Coast.*

[12,114]

Rates in Other Sub-Areas for Gas Under Contracts Dated from January 1, 1961 through September 30, 1968

30. In the sub-areas other than Mississippi and Alabama, we establish January 1, 1961, as the date of division between the first and second vintages of gas. This is done to avoid multiplicity in division dates in the different producing areas, and in accordance with our reasoning in *Texas Gulf Coast, supra* and *Southern Louisiana II, supra.*

31. In accordance with the initial decision, we find the just and reasonable area rates for gas delivered at a central point, the tailgate of a plant or a point on the buyer's pipeline under contracts dated after 1960 and before October 1, 1968, to be, for the period prior to January 1, 1965:

	Cents per Mcf (at 14.65 psia except as noted)
Other Oklahoma	18.4
Texas District 9	18.7
Northern Arkansas	17.8
Texas District 6	18.1 [21]
Northern Louisiana (at 15.025 psia)	19.6
Southern Arkansas	17.25

[12,115]

These rates, in accordance with our determination in *Texas Gulf Coast* (pages 39-40) shall escalate .5 cent per Mcf on January 1, 1965, an additional .5 cent on October 1, 1968, and an additional cent on October 1, 1973.

32. These rates are below those provided for similar gas in the adjacent Hugoton-Anadarko area, but the pricing history of the two areas indicates price differentials of approximately the same amounts. The *Texas Gulf Coast* rates were slightly below those here provided. While somewhat higher rates were approved in *Southern Louisiana II* for similar gas (even after adjustment for

[21] No rates are fixed for Texas District 5 for contracts prior to October 1, 1968, since there were no jurisdictional sales from this sub-area prior to that time.

higher state taxes and pressure base), the historical price differences between Other Southwest and Southern Louisiana are much greater. Southern Louisiana gas is also of higher average quality, and the cost of finding and producing Southern Louisiana gas is greater.

33. The summary of prices in Other Southwest, Appendix C hereto, indicates no reason to revise the cost-based rates upward.

[12,116]

Rates in Other Sub-Areas for Gas Under Contracts Dated Before 1961

34. A comparison of the averages prices paid by interstate pipelines for jurisdictional and intrastate gas from all producers in 1960 with the initial decision's cost-based prices for pre-1961 gathered gas is as follows, in cents per Mcf: [a]

	Jurisdictional Prices	Intrastate Prices	Initial Decision
Other Oklahoma	12.09	16.78	17.5
Texas District 9	13.98	13.96	17.8
and Northern Arkansas [b]			17.0
Texas Districts 5 and 6	12.02	13.01	14.1
anud Southern Arkansas [c]			13.5
Northern Louisiana	12.97	8.95	15.8

[a] Exh. 60, Schedule 7, Sheet 3. All prices are at 14.65 psia except in northern Louisiana (15.025 psia).

[b] Combined with Other Oklahoma in Exhibit 60, Schedule 7.

[c] Combined with Texas Districts 5 and 6 in Exhibit 60, Schedule 7.

Cost computations are notoriously imprecise. Where the districts on which the computations are based are as small as they are here, it becomes even more questionable whether the computed costs are representative.

35. The cost-based rates in the initial decison are high enough so that no adjustment is indicated by the prices in Appendix C, except in northern Louisiana, even allowing for the distortions caused by averaging the prices of gathered gas, ungathered gas and gas of varying quality.[22]

36. Interstate and intrastate price levels are below the cost-based rates in the initial decison. The lower guideline rates of 11 cents in Other Oklahoma, 14.5 cents in Texas Districts 5 and 9, 14 cents in Texas District 6, and 15.75 cents in northern Louisiana are exceeded by the cost-based rates.

[12,118]

37. In *Texas Gulf Coast*, we found a rate of 15 cents per Mcf to be within the zone of reasonableness, based on the initial decision's historical cost computation of 13.68 cents per Mcf. Upon similar reasoning, and because of the 15-cent price in the adjacent Texas Gulf Coast area, we find a 15-cent rate proper in Texas District 6. The comparable northern Louisiana rate, 16.7 cents per Mcf (adjusted for tax and pressure differences), we find just and reasonable for the same reasons, and because of the price patterns indicated in Appendix

[22] The distortion is especially great in Texas District 9, where all gas sold is ungathered. We have set forth our conclusions on the basis of gathered gas in this sub-area for the sake of uniformity and ease of comparison.

C. In the remaining Other Southwest sub-areas, the initial decision costs exceeded adjacent area prices.

38. We adhere to our view, for the reasons expressed in *Texas Gulf Coast*,[23] that all gas in a given sub-area under contracts dated prior to October 1, 1968, should be subject to the same base area rates after that date. The cost-based rates in the initial decision for gas under contracts dated prior to 1961 will undergo two escalations, the first on January 1, 1965, and the second on October 1, 1968, to bring its base area rates on October 1, 1968, to the same level as gas under contracts dated from 1961 through September 30, 1968.

[12,119]

39. In summary, we find that the just and reasonable base area rates in these sub-areas for gathered gas under contracts dated prior to 1961 are as follows (in cents per Mcf at 14.65 psia unless otherwise noted):

	For Gas Delivered:		
	Prior to January 1, 1965	From January 1, 1965 Through September 30, 1968	After September 30, 1968
Other Oklahoma	17.5	18.4	19.4
Texas District 9	17.8	18.7	19.7
Northern Arkansas	17.0	17.9	18.8
Texas District 6	15.0	17.0	19.1
Northern Louisiana [a]	16.7	18.6	20.6
Southern Arkansas	14.4	16.25	18.25

[a] At 15.025 psia.

[23] These reasons include: increased drilling costs, well rehabilitation, equipment repair and replacement revenues from flowing gas as a source of funds for new investments. See *Texas Gulf Coast*, p. 38-39.

40. Base area rates in all these sub-areas shall escalate an additional one cent on October 1, 1973, in accordance with our determination in *Texas Gulf Coast* and for the reasons there stated (page 40).

[12,120]

Ungathered Gas

41. For ungathered gas we adopt the initial decision's determination that 1.5 cent per Mcf should be subtracted from the area rate for gathered gas in Other Oklahoma, Texas District 9 and northern Arkansas; 1.25 cent in the state domain in Mississippi and Alabama; and 1.0 cent in Texas Districts 5 and 6, northern Louisiana and southern Arkansas.

Casinghead Gas

42. The Examiner indicated that casinghead gas should receive the same price as flowing gas. For the reasons we stated in *Texas Gulf Coast, supra;* and *Southern Louisiana II, supra,* we reject this conclusion. Casinghead gas should receive the same rates as gas-well gas of comparable vintage and quality.

[12,121]

Quality Standards

43. We adopt the quality standards and resulting base area rate adjustments provided in the initial decision. That decision, however, did not fix standards for gas that may be produced in the Federal domain offshore of Mississippi. It is to be expected that the quality of gas found there will conform to that of gas now being produced in the Federal domain offshore of Louisiana. Ac-

cordingly, upward adjustments will be permitted when the Btu content of the gas exceeds 1050, and downward adjustments will be required when the Btu content is less than 1000. The other qaulity standards and adjustments will be as provided in the initial decision.

[12,122]

Minimum Rates

44. The Commission has been held to be "without authority to abrogate the existing contract prices unless it first concluded that they 'adversely effect the public interest.'" *Permian Basin Area Rate Cases*, 390 U.S. 747, 820 (1968). The Natural Gas Act contemplates abrogation of existing contracts "only in circumstances of unequivocal public necessity." Ibid, page 822. As in *Texas Gulf Coast* (pages 49-50), we are here "unable to make the finding that existing rates below any of the proposed minimum prices would 'prevent or retard future exploration' which was the basis of the Commission's decision to establish a minimum rate in the *Permian* case." The volume of gas below the Staff's proposed minimum rates is small, and steadily declining; the additional revenue generated would be so small as to have only a *de minimis* effect on exploration and development.

[12,123]

Moratorium

45. A moratorium on price increases above the applicable area rates will be imposed until July 1, 1976.

Refunds

46. In prior cases in which no settlement proposal was adopted by the Commission, refunds were required on amounts collected in excess of the applicable area rates for periods for which such amounts were collected subject to refund in Section 4(e) proceedings. (See the decisions in *Permian, Southern Louisiana* and *Texas Gulf Coast.*) In any case where an initial price has been authorized in a final unconditional permanent certificate, amounts collected thereafter are subject to refund in a Section 4(e) proceeding only to the extent such amounts exceed the initial price. *F.P.C.* v. *Sunray DX Oil Corporation*, 391 U.S. 9, 24 (1968).

47. In the present case, refund of excessive amounts collected subject to refund in Section 4(e) proceedings will be ordered whether consolidated in this proceeding or not. The refunds here ordered are of such small amount that a refund credit would not provide an incentive to any materially increased exploration and development program; in this respect Other Southwest is different from Southern Louisiana and Texas Gulf Coast.

[12,124]

Special Exemption Procedure

48. The special exemption procedure preciously established in other areas will also be open to all those making jurisdictional sales of gas in the Other Southewest area.

[12,125]

CONTAINERS OF FREIGHT AND AIR RATES PER
CENTUM CWT WITH POSTAL SURCHARGE, CANCELLING AND SUPERSEDING 1/

	Present Rate Area Rates 2/			Initial Rates			Reduction Rates 3/					
	Contracts Effective Jan. 1, 1956	Contracts Effective Apr. 1, 1956	Contracts eff. Sept. 1, 1956	Contracts Effective Apr. 1, 1961	Contracts Effective Apr. 1, 1962		Optional Rate Points With Prices Reduced	With Prices Reduced to Zone Destination Established	With All Points Destination Established (Except Intra-Alaska)	Initial Effective	Initial Effective
Other Oklahoma	19.4	19.4	20.79	19.3	18.4		13.0	13.5	15.0	15.0	15.0 1/
Texas Districts 3	19.7	19.7	21.0	19.6	18.7		14.3	14.4	15.0	15.0	14.3
Northern Arkansas	19.8	19.8	21.0	19.6	17.6		Same	Same	Same	Same	Same
Texas Districts 5	21.4	21.4	22.8	14.1	16.1		14.3	14.4	14.4	15.0	14.3
Texas Districts 6	19.1	19.1	20.5	14.1	16.1		14.3	14.4	15.0	15.0	15.0
Northern Louisiana (46 15,000 pds)	21.6	21.6	23.0	13.9	15.6		15.79	16.37	16.78	16.79	16.79 1/
Southern Arkansas	19.79	19.79	21.2	13.9	17.29		Same	Same	Same	Same	Same
Eastern Mississippi (46 15,000 pds)	20.0	20.0	21.0	15.79	19.29		14.0	14.43	15.29	21.3	20.6 2/
Northern Alabama (46 15,000 pds)	20.0	20.0	21.0	15.79	19.29		Same	Same	Same	Same	Same
Federal Zones (Ryukyus Islands) 46 15,000 pds)	21.4	21.4	22.5	Same	Same		Same	Same	Same	Same	Same

1/ Prices are in c/kef at 15.43 pds except as noted.

2/ Rates will continue one year for 46 on October 1, 1956, for gas from the Federal Zones (Ryukyus Mississippi) and on October 1, 1957 for gas from all other differences. For Optional gas, 1-7 cents per kef will be collected from the Ryukyus rate in Other Oklahoma, Texas Districts 5 and Northern Arkansas; 1.57 cents per kef in Mississippi and Alabama, and 1.0 cents per kef in Texas Districts 6 and 7, Northern Louisiana and Southern Arkansas.

3/ Reduction rates were established by Statement of General Policy, No. 61-1, September 28, 1960 and First Amendment, October 25, 1960; Second Amendment, November 25, 1960; October 26, 1961; March 27, 1962; and Seventh Amendment, October 27, 1962.

4/ Opinion 446, December 27, 1944.

5/ Opinion 330, October 12, 1959.

6/ Order 6741-A, March 14, 1962.

7/ Opinion 446, December 26, 1944.

FURTHER FINDINGS AND ORDER

Jpon consideration of the entire record in this proding, which includes public notice, public hearing h opportunity for the submission of oral and documtary evidence, for cross-examination, and for the mission of rebuttal evidence, initial decision by an miner, exceptions thereto, and oral argument before Commission, *the Commission further finds*:

1) The Other Southwest Area comprises: (a) The te of Mississippi and the Federal domain offshore reof; (b) Northwest Alabama, consisting of Marion, yette, Lamar and Pickens Counties; (c) Northern Louna, consisting of that portion of Louisiana lying north the 31 degree parallel through Concordia, Pointe Cou- Avoyelles, Rapides, and Vernon Parishes; (d) Texas ilroad Commission Districts Nos. 5, 6, and 9; (e) ner Oklahoma, consisting of Adair, Atoka, Bryan, rter, Cherokee, Choctaw, Cleveland, Coal, Comanche, tton, Craig, Creek, Delaware, Garvin, Greer, Harmon, skell, Hughes, Jackson, Jefferson, Johnstown, Kay, owa, Latimer, Le Flore, Lincoln, Logan, Love, Clain, McCurtain, McIntosh, Marshall, Mayes, Murray, skogee, Noble, Nowata, Okfuskee, Oklahoma, Okmul-, Osage, Ottawa, Pawnee, Payne, Pittsburgh, Ponto-, Stephens (except Carter-Knox Area), Tillman, lsa, Wagoner, Washington, Pottawatomie, Pushmataha, gers, Seminole, and Sequoyah Counties; (f) Northern kansas, consisting of Sevier, Howard, Pike, Clark, llas, Cleveland, Drew, and Desha Counties, and all er Arkansas counties north of this group; (g) South- Arkansas, consisting of Little River, Hempstead, ller, Lafayette, Nevada, Columbia, Oachita, Union, lhoun, Bradley, Ashley, and Chicot Counties, Arnsas.

(2) Each of the respondents [24] listed in Appendix A to this Opinion and Order is, and at the time of all past sales with which we are here concerned was, a "natural gas company" within the meaning of the Natural Gas Act and is engaged in the sale of natural gas in interstate commerce for resale for ultimate public consumption subject to the jurisdiction of this Commission.

[12,127]

(3) Past, present, and proposed sales of natural gas to which the order herein applies are subject to the jurisdiction of this Commission.

(4) Rates for all sales of natural gas, subject to the jurisdiction of the Commission by the producers in the Other Southwest area that are above the applicable area rates prescribed herein, have not been shown to be just and reasonable or otherwise lawful under the provisions of the Natural Gas Act and should be disallowed, and refunds should be required as hereafter provided.

(5) The just and reasonable rates for past, present, and prospective sales of natural gas to which this order applies are the applicable area rates set forth in ordering paragraphs (A) and (B) below.

(6) Rates in excess of the applicable just and reasonable rates determined herein are in that respect unjust and unreasonable.

(7) It is necessary and appropriate to carry out the provisions of the Natural Gas Act that the Commission adopt the orders and regulations herein prescribed.

---

[24] Where the term "respondents" is used in the finding and ordering paragraphs hereinafter set forth, it is to be regarded as referring to all named respondents in the Commission orders issued in this case, and to all parties on whose behalf such named respondents have filed FPC gas rate schedules for sales of gas produced in the Texas Gulf Coast area.

(8) Except as herein granted the exceptions to the initial decision and proposed order should be denied.

Acting pursuant to Sections 4, 5, and 16 of the Natural Gas Act (52 Stat. 822, as amended, 823, 830; 15 U.S.C. 717c, 717d, 717o) and Sections 553, 556, and 557 of Title 5 of the United States Code (the Administrative Procedure Act, 60 Stat. 238, 239, 241, 242, as codified September 6, 1966, by 80 Stat. 383, 384, 386, 387), the Commission *orders:*

(A) Part 154 of the Commission's Regulations under the Natural Gas Act, Subchapter E, Chapter I, Title 18 of the Code of Federal Regulations is amended by adding a new section 154.109 reading as follows:

[12,128]

Part 154—Rate Schedules and Tariffs

* * * *

§ 154.109 Area Rates—Other Southwest areas.

(a) From and after January 1, 1972, and prior to July 1, 1976, no rate or charge made, demanded or received under a rate schedule filed pursuant to this Part for gas produced in the Other Southwest area shall exceed the applicable area rate prescribed by this section except in compliance with a specific order of the Commission.

(b) Applicable area rate means the base area rate established in paragraph (c) adjusted to the extent required by paragraph (d).

(c) *The Base Area Rates.* The following base area rates per Mcf (at 14.64 psia unless otherwise noted) are hereby established for the period from January 1, 1972, to July 1, 1976, subject to the adjustments provided in paragraph (d), for gas gathered and delivered by the

seller at either a central point in the field, the tailgate of a plant or point on the buyer's pipeline, or an offshore platform to the buyer's line, by the following:

(1) Gas sold under contracts dated prior to October 1, 1968:

	From January 1, 1972 Through September 30, 1973	Beginning October 1, 1973
Other Oklahoma	19.4	20.4
Texas Railroad District No. 9	19.7	20.7
Northern Arkansas	18.8	19.8
Texas Railroad District No. 6	19.1	20.1
Northern Louisiana (at 15.025 psia)	20.6	21.6
Southern Arkansas	18.25	19.25
Mississippi and Alabama (at 15.025 psia)	20.0	21.0

[12,129]

(2) Gas sold under contracts dated on or after October 1, 1968:

	From January 1, 1972 Through Sept. 30, 1973	Beginning October 1, 1973
Other Oklahoma	23.75	24.75
Texas Railroad District No. 9	24.0	25.0
Northern Arkansas	23.0	24.0
Texas Railroad Districts Nos. 5 and 6	23.5	24.5
Northern Louisiana (at 15.025 psia)	25.0	26.0
Southern Arkansas	22.5	23.5
Mississippi and Alabama (at 15.025 psia)	25.0	26.0

	From January 1, 1972 Through Sept. 30, 1973	Beginning October 1, 1973
Federal Domain Offshore of Mississippi	26.0	27.0

(3) The applicable area rate shall be adjusted downward, for gas delivered closer to the wellhead than a central point in the field, the tailgate of a plant, a point on the buyer's pipeline or an offshore platform on the buyer's line by the following:

Other Oklahoma, Texas Railroad District No. 9, and Northern Arkansas	1.5 cent per Mcf
Texas Railroad Districts Nos. 5 and 6, Northern Louisiana and Southern Arkansas	1.0 cent per Mcf
Mississippi and Alabama	1.25 cent per Mcf

[12,130]

(d) *Quality Standards and Adjustments to the Base Area Rates.* The base area rates established in paragraph (c) are subject to adjustment as follows:

(1) *Btu Adjustment*—For gas with more than the maximum standard of Btu's per cubic foot, at 60°F and 14.73 psia, upward adjustments shall be made on a proportional basis from a base equal to the maximum standard. For gas with less than the minimum standard of Btu's per cubic foot, at 60°F and 14.73 psia, downward adjustments shall be made on a proportional basis from a base equal to the minimum standard. Measurement of Btu shall be on a wet basis. The applicable maximum and minimum standards are:

	Maximum	Minimum
Other Oklahoma, Texas Railroad District No. 9 and Northern Arkansas	1060	1000
Texas Railroad Districts Nos. 5 and 6, Northern Louisiana and Southern Arkansas	1030	1000
Mississippi and Alabama	990	950
Federal Domain Offshore of Mississippi	1050	1000

(2) The following additional quality standards shall apply:

(i) *Water Content*—The gas shall not contain in the aggregate more than seven pounds of water, either in the form of liquid or vapor, per million cubic feet of gas at 60°F and 14.73 psia (.007 lbs. per Mcf).

(ii) *Hydrogen Sulphide*—The gas shall not contain more than one grain of hydrogen sulphide per one hundred cubic feet of gas at 60°F and 14.73 psia (10 gr. per Mcf).

(iii) *Total Sulphur*—The gas shall not contain more than 20 grains of total sulphur per one hundred cubic feet of gas at 60°F and 14.73 psia (200 gr. per Mcf).

(iv) *Carbon Dioxide*—The gas shall not contain more than 3 percent by volume of carbon dioxide.

(v) *Other Impurities*—The gas shall contain no oxygen, dust, dirt, gum, or other impurity in sufficient amounts to require the buyer to incur processing costs to eliminiate such impurities in order for the gas to meet either customary commercial

standards or the customary requirements of any of the interstate pipelines in the area.

(vi) *Delivery Pressure*—The gas shall be delivered at a pressure sufficient to enter the buyer's pipeline except that a minimum of 500 psig must be available at the point of delivery.

(3) When a purchaser buys gas which deviates from the quality standard established in subparagraph (2) above, the base area rate shall be adjusted for any deviations from such standards as follows:

(i) The applicable area rate shall be adjusted downward by the net cost, actually incurred prior to ultimate consumption, of processing the gas to bring it up to standard.

(aa) If the processing is performed by the purchaser, a reasonable return upon the net investment should be included as part of the processing cost incurred in bringing the gas up to pipeline quality.

(bb) If such processing reduces the volume of the gas, the purchaser shall pay for only the volume remaining after processing.

(ii) In the case of delivery by seller of gas containing carbon dioxide in excess of the standards herein permitted, notwithstanding anything to the contrary in Paragraph (2) (iv), the producers shall have the alternative of receiving payment for the total volume of gas delivered, including the carbon dioxide, providing that the Btu content of the gas is measured before the removal of the carbon dioxide for the purposes of the Btu adjustments specified in this order, or receiving payment for the volumes exclusive of the carbon dioxide with the Btu measured by the volumes of gas only.

(f) Prior to July 1, 1976, any seller seeking to charge a rate in excess of the applicable area rate or requesting a change in the applicable area rate must file a petition for waive or amendment of this section pursuant to Section 1.7(b) of the Commission's Rules of Practice and Procedure (18 CFR 1.7 (b)) fully justifying the relief sought in the light of this opinion and order. Prior to July 1, 1976, the seller may not file any rate increase in excess of the applicable area rate herein prescribed unless and until the Commission grants the petition.

(B) For the purpose of computing refunds in all Section 4(e) proceedings now pending with respect to gas produced in the Other Southwest area, the following base area rates (at 14.65 psia unless otherwise noted) are hereby established, for gas gathered and delivered by the seller at either a central point in the field, the tailgate of a plant, or a point on the buyer's pipeline:

(1) Gas sold under contracts dated prior to January 1, 1961:

	Prior to January 1, 1965	From January 1, 1965 Through September 30, 1968	From October 1, 1968
Other Oklahoma	17.5	18.4	19.4
Texas Railroad District No. 9	17.8	18.7	19.7
Northern Arkansas	17.0	17.9	18.8
Texas Railroad District No. 6	15.0	17.0	19.1
Northern Louisiana (at 15.025 psia)	16.7	18.6	20.6
Southern Arkansas	14.4	16.25	18.25
Mississippi and Alabama (at 15.025 psia)	19.0	19.5	20.0

(2) Gas sold under contracts dated from January 1, 1961, through September 30, 1968:

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	Prior to January 1, 1965	From January 1, 1965 Through September 30, 1968	From October 1, 1968 Until January 1, 1972
Other Oklahoma	18.4	18.9	19.4
Texas Railroad District No. 9	18.7	19.2	19.7
Northern Arkansas	17.8	18.3	18.8
Texas Railroad District No. 6	18.1	18.6	19.1
Northern Louisiana (at 15.025 psia)	19.6	20.1	20.6
Southern Arkansas	17.25	17.75	18.25
Mississippi and Alabama (at 15.025 psia)	19.0	19.50	20.0

(3) Gas sold under contracts dated on or after October 1, 1968:

Other Oklahoma	23.75
Texas Railroad District No. 9	24.0
Northern Arkansas	23.0
Texas Railroad Districts Nos. 5 and 6	23.5
Northern Louisiana (at 15.025 psia)	25.0
Southern Arkansas	22.5
Mississippi and Alabama (at 15.025 psia)	25.0

(4) The applicable area rate shall be adjusted downward for gas delivered closer to the wellhead than a central point in the field, the tailgate of a plant, or a point on the buyer's pipeline in the same amounts provided in such cases in paragraph (d) (4) of Section 154-.109 as added by ordering paragraph (A) hereof, to Part

154 of the Commission's Regulations Under the Natural Gas Act, and shall be subject to the same quality standards and adjustments as provided by paragraph (d) of said Section 154.109.

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(C) The applicable area rates as defined in ordering paragraph (A) above, shall be effective from and after January 1, 1972 and any amounts collected in excess thereof on or after that date shall be subject to refund plus interest at 7 percent. In addition, with respect to the rates involved in Section 4(e) proceedings set out in Appendix A, the applicable area rate as defined in paragraph (B) above, shall be effective from the date such Section 4(e) rates were collected subject to refund and all amounts collected under those Section 4(e) rates prior to the effective date of this Opinion in excess of the applicable area rate shall be subject to refund, plus interest at the rate specified in the respective Section 4(e) proceeding, in accordance with the provisions of ordering paragraphs (E) and (F) herein; provided, however, that with respect to such 4(e) dockets no refunds are required below the rate allowed in a final, unconditioned permanent certificate previously granted for such sale.

(D) By February 1, 1972 each respondent shall file a supplement to each applicable rate schedule, effective as of January 1, 1972, reflecting any reductions required to bring any or all of its rates into conformity with the applicable base area rates established by ordering paragraph (A) herein. The timely filing of a completed statement in conformity with Appendix D hereto shall constitute compliance with this paragraph (D).

(E) Each person having on file with this Commission a rate schedule with regard to gas produced or sold

within the Other Southwest area, or hereafter filing such a rate schedule (including a contract or amendment adding acreage or new reserves) shall, with regard to such rate schedule or amendment, file by February 1, 1972, or within 90 days from the date of first delivery under the rate schedule or amendment, whichever is later, a statement in conformity with Appendix D hereto. All statements herein required shall be signed by both the seller and the purchaser. If the seller and the purchaser are unable to agree upon any or all of the particulars entering into the computation of the applicable area rate, the seller shall file the statements herein required which shall indicate the absence of agreement and supply the information required to compute the applicable area rate as well as the

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contentions of the parties with respect to the quality and amount of the adjustment for any item in dispute. The purchaser may file a separate statement setting forth its views within the period herein provided.

(2) The statement filed hereunder which reflects full agreement between the seller and purchaser shall be deemed accepted by the Commission unless the Commission, within 120 days after such filing, shall otherwise order. In the event of disagreement between the seller and purchaser or, where the Commission otherwise determines that the statement filed is inconsistent with the provisions of ordering paragraph (A) herein, the Commission will after appropriate proceedings, prescribe the applicable area rate to be applied.

(3) Any respondent will be exempt from filing the statement required by subparagraph (1) hereof for any sales which are "small producer sales" as defined in the

Commission's Regulations under the Natural Gas Act if a producer seeks to qualify thereunder. If the Commission subsequently finds that such a producer does not qualify as a small producer such applicant shall be required to file the statement required by subparagraph (1) hereof within 90 days after any such commission finding.

(F) *Refund Reports.* By February 1, 1972, refund reports shall be filed with this Commission in triplicate, and one copy served on the buyer, by each respondent involved in one or more of the Section 4(e) proceedings set out in Appendix A and as to which refunds are required under the terms of this decision. Within 20 days from the filing of the refund report the buyer shall file its written concurrence or disagreement with such report. Each producer within 30 days of filing a refund report shall notify each working interest owner under each rate schedule of any refunds, including interest, applicable to its gross interest. The report shall set forth the following information (if more than one rate schedule is involved the respondent shall supply the information for each schedule separately):

(i) The rates collected during the period subject to refund, and the periods during which each rate was collected.

(ii) The volume of gas sold at each such rate.

(iii) The difference between the total amount collected during the period subject to refund and the amount that would have been collected at the applicable area rate as defined herein subject to the proviso of ordering paragraph (C).

(iv) The computation of the applicable area rate and the basis for any difference between it and the base area rate.

(v) The interest, at rates as specified in each Section 4(e) proceeding, on the above refundable excess revenues, subject to the limitation by Section 154.102(f) of the Commission's Regulations Under the Natural Gas Act. The interest shall be calculated to the date of the refund report.

(G) *Treatment of Refunds.* Each respondent shall retain the amounts shown in the report required under ordering paragraph (F) subject to further order of the Commission directing the disposition of those amounts. If a respondent elects to commingle these retained refunds with its general assets and use them for its corporate purposes, it is authorized so to do after a notice to the Commission; and it shall pay interest thereon at the prime rate, in effect as of 12:00 noon on the date of issuance of this Opinion and Order for loans made by the Chase Manhattan Bank, on all funds thus available from the effective date of this order to the date on which they are paid over to the person ultimately determined to be entitled thereto in a final order of the Commission. If a respondent elects to deposit the retained funds in a special escrow account, the respondent shall make such deposit and shall comply with the escrow agreement requirements of Section 250.12 of the Regulation Under the Natural Gas Act (18 CFR 250.12). Unless notified to the contrary by the Secretary within 30 days from the date of filing thereof, the escrow agreement shall be deemed to be satisfactory and to have been accepted for filing.

(H) The provisions of Section 154.63 of the Commission's Regulations Under the Natural Gas Act are waived to permit pipeline companies to file rate increase

applications to track producer rate increases filed pursuant to the provisions of this order; such tracking applications may be filed by pipeline purchasers or by pipelines purchasing from such pipeline purchasers which are not authorized to track rate changes of their suppliers with regard to gas from Other Southwest, provided that pipelines filing such an adjustment

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submit working papers with the filing showing the computation thereof, and, provided further, that the rate or rates as revised by such rate increase applications shall be collected subject to reduction and refund from the effective date of such increased rate or rates.

(I) Section 2.52, Part 2, General Policy and Interpretations, of the Commission's General Rules is waived so as to permit the filing of a rate increase application to track producer rate increases filed pursuant to the provisions of this order by a pipeline purchaser or by a pipeline purchasing from such a pipeline purchaser where the pipeline has a proposed increased rate or rates under suspension at the time of such tracking application.

(J) The procedures for establishing and revising the amount of reserves in new dedications, and the reports required, will be established by later order of the Commission.

(K) These proceedings shall remain open for such further action as may be necessary with respect to individual respondents and such other action as may be necessary in the premises.

(L) The Secretary of the Commission is authorized to accept filings of rate changes and quality statements made in accordance with this opinion and order.

(M) Except as herein granted the exceptions to the initial decision and proposed order are hereby denied.

(N) The Secretary shall cause prompt publication of the findings and ordering paragraphs, together with notice of the availability of this entire Opinion, to be made in the Federal Register.

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(O) This order does not relieve any of the Applicants herein of any responsibility imposed by, and is expressly subject to, the Commission's Statement of Policy Implementing the Economic Stabilization Act of 1970 (P.L. 91-379, 84 Stat. 799, as amended by P.L. 92-15, 85 Stat. 38), including such amendments as the Commission may require, and Executive Order No. 11615.

By the Commission.

KENNETH F. PLUMB,
Secretary

[SEAL]

APPENDIX A

PART I

RESPONDENT INDEPENDENT PRODUCERS[1]

Adams, N. L., Sr.
Alexander, C. W.
Alexander, E. B., Jr.
Allied Materials Corporation
Alston, Francis H.
Amax Petroleum Corporation
A'Mell Oil Properties
Amerada Hess Corporation
Americana Oil & Gas Properties of Texas, Inc.
American Exploration Development Corporation
American Petrofina, Inc.
American Petrofina Company of Texas
American Realty and Petroleum Corporation
American Trading and Production Corporation
Anadarko Production Company
An-Son Corporation
Anderson, Jacqueline
Anderson Petroleum
Andrewski, H. C. & Gertrude B.
Anisman, M., Trustee
Anisman, Morris
Apache Corporation
Apco Oil Corporation
Argo, M. M.
Arkla Exploration Company
Arrington, J. H.
Ascher, M.
Ashland Oil and Refining Company
Athens, E. J.
Atkins, Katherine Adger
Atlantic Richfield Company
Austral Oil Company, Inc.
B and A Pipe Line Company
Bailey, Virginia Mitchell
Bander, Joe
Barker, Walter L.
Barnes, Earl E.
Barnwell Debardeleben Oil Company
Barnwell and Kinzler
Barnwell Inc.
Barnwell Production Company
Barrett, Charlotte Osborn
Basin Operating Company
Bass, Harry W.
Thelma Bauerdorf and Constance Cartwright Trustees for George F. Bauerdorf, Deceased
Beacon Oil & Refining Company
Beall, Alton G.
Beard Oil Company
Behring's Production Company, Inc.
Belgam Oil Company, Inc.
Berry, Thomas E.
Biedenharn, Betty Osborn

[1] All persons named herein and all parties on whose behalf such persons have filed FPC gas rate schedules for sales of gas produced in the Other Southwest Area are respondents in this proceeding, including their successors and assigns. See page 9 for listing of company name changes.

Big Chief Drilling Company
Biggs, Robert A., Jr.
Biglane, D. A.
Blair, B. B.
Bodcaw Company
Bohnsack, Richard L.
Bond, Durbin
Bond, Roland S.
Borden, S. P.
Boteler, R. H.
Boteler, R. T.
Bracken Oil Company
Brandenburg, R. P.
Breckenridge Gasoline Company
Brennan, Harry W., Jr.
Brian, C. A.
Bridewell, Billy
Brightwell, Donald
Briscoe, Powel
Powel Briscoe Inc.
Briscoe, Roy E.
Bristol, R. A.

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Brooks, Jesse M.
Brooks, Jesse M. & M. James Brooks
Zach Brooks Drilling Company
Brown, George R.
Brown, L. D. and Trant, Sam
Broyles, C. W.
Broyles, Harvey
Bryant, W. H.
Buckwalter, Charles F.
Burk Gas Corporation
Burk Royalty Company
Burnett, T. C. and Ruby C., Estate
Burnham, Joe M.
Burns, L. T., Estate
Burns, R. G.
Burton, C. P.
Butler, J. R.
J. R. Butler and Company
C. F. and H. Oil Company, Inc.
Caddo Pine Island Corporation
California Company, a Division of Chevron Oil Company, The
Inez Calmes Executrix of the Estate of Kermit Calmes, Deceased
Calto Oil Company
Calvert-Mid American Inc.
Cameron, A. A. d/b/a Cameron Oil Company
George E. Cameron Inc.
Canary, S. C.
Cararas, Jerome A.
Caraway, Reagan J.
Cargill, Robert
Carpenter, E. B.
Carter-Jones Drilling Company, Inc.
Car-Tex Producing Company
Caruthers, J. D.
Caruthers Operating Company, Inc.
Carver, Mrs. Helen d/b/a Anthony Oil Company
Casey, Carl
Caska Corporation
Cassard, A. R.
Central Commercial Company
Central Oil Company
Champlin Petroleum Company
Chastain, M. E.
Chevron Oil Company, Western Division
Chicago Mill & Lumber Company
Chisholm, Alexander F.
A. F. Chisholm d/b/a The Brandon Company
Cities Service Company
Cities Service Oil Company
Citizens Bank of Hattiesburg, Mississippi

Claiborne Gasoline Company
Clark, Anson L.
Clark and Cowden
Clark, F. A.
Clay, Thomas W. and Walker, J. G. d/b/a Clay-Walker
Clearly Petroleum Corporation
Cloud, Robert E.
Coastal States Gas Producing Company
Coats, Alton
Cochran, Phil K.
Coffield, H. H.
Cohen, Don
Coles, Marvin J.
Coles, Otis C., Jr.
Collins, George Fulton, Jr.
Commercial Solvents Corporation
Compadre Oil Corporation
Continental-Emsco Company
Continental Oil Company
Cook, Tom, Jr.
Cook, William H.
Cotton, Doyle W., Jr.
Cotton Valley Community
Coulston Drilling Company
Coutant, A. E.
Cox, Edwin L.
Crescent Drilling Company, Inc.
Creslenn Oil Company
Crest Petroleum Inc., Agent
Crichton, John H.
Criner Processing
Crockett, M. W. and Charles Kelly d/b/a Crockett & Kelly
Crow, Mrs. Cordelia K.
Crow, David, Trustee

Crow Drilling and Producing Company
Milton Crow Inc.
Crystal Oil and Land Company
Culpepper, Curtis
Curry, W. C.
Cuttychamp Oil & Gas Corporation
Cyprus Mines Corporation
Dal-Rock Production Company
Darby, Beulah K.
Daube, Olive H. d/b/a Daube Company
Davidor & Davidor, Inc.
Davis, C. D.
Davis, Paul R. and Lester B. Wood
Davis, Waymon L.
Debardeleben, Charles F. Jr.
Dees, M. H.
Delaney, W. A., Jr.
Delta Drilling Company
Delta Gulf Drilling Company
Deposit Guarantee Bank & Trust Company
Despot, George J.
Dial, J. B.
Discovery Oil & Gas Company, Inc.
Dorchester Gas Production Company
Dorfman, Elizabeth F., Trust
Dorfman, Louis
Dorfman, Sam Y., Jr.
Draughn, Paul V., Jr.
Draughn, Paul V., Sr.
Dugan, Thomas
Dunbar, Blaine
N. V. Duncan Drilling Company
Estate of N. V. Duncan
Duncan, Walter
E. Dunlap, Jr.
Eason Oil Company
Ward M. Edinger, Inc.

Edwards, Robert J., Jr.
Ekor Chemical Corporation
Elledge, Vernon and Hall
Ellis, H. A. d/b/a All Star Gas Company
Elm Grove Gathering System Inc.
Erickson, E. L.
Evans, James P., Jr.
Fagadau, Sanford P.
Fair Oil Company
Fairfield Oil Company
Falcon Seaboard Drilling Company
Feazel, W. C., Estate
Felsenthal, S. J., Estate
Fender, Harris R.
Ferguson, Hershal C.
Ferguson Oil Company Inc.
Fields, Bert, Jr.
Fleet, Howard W.
Florsheim, S. L.
Fohs, Julius F. Estate of
Ford, Evon A.
Helen H. Feldman, Gertrude M. Reilly and Raymond J. Gertz, Trustees, Estate of Joseph Feldman
Forest Oil Corporation
Forgey, R.
Forgotson, James M.
Foster, W. H.
Four States Drilling Company, Inc.
Franks, John
Franks Petroleum, Inc.
Joseph F. Fritz
Fryer and Hanson Drilling Company
Gage, Coke L.
Gammill, Dave
Gant, Walter H.
Gas Rock Corporation
Gas Transmission Company
Genecov, A. S., Trustee
General American Oil Company of Texas
Genere Gas Industries Inc.
Geological Exploration Company
Getty Oil Company
Gibbons, Ed
Gilbert, Arch B.
Glassell, A. C., Sr.
Glassell, Alfred C., Jr.
Glassell and Glassell
Glen Rose Gasoline Company
Godfrey, Roy A.
Goins, J. I.
Gose, Steve
Gragg Drilling Company
Graokla Gas Corporation
Greenbaum, R. R. d/b/a Time Petroleum Company
Greenville Gasoline Company Inc.

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Grigsby, Jack W.
Grimes, Otha H.
Gulf Mobile and Ohio R. R. Company
Gulf Natural Gas Corporation
Gulf Oil Corporation
H & H Oil & Gas Company
Hall, Frank J.
Hall, G. C.
Hall, Stanton A.
Hamill, Claud B.
Hamilton Gas Company
Hamman, Blake
Hamon, Jake L.
Harden, Jack
Hardey, Charles O.
Hargrave, Horace C.
Harper Oil Company

Harris, James W.
Harrison, Wallace
Harvey, W. W. & Sojourner, W. C.
Hawkins, H. L. & H. L., Jr.
Hayes, Marshall A., Jr.
Heape, Gene
The Hefner Company
Heidelberg, Cecil F., Jr.
Roy Heidelberg II
Heldt, James D.
Helmerich and Payne Inc.
Henry, S. O., Jr.
Herold, Simon
Maxwell Herring Drilling Corporation
Hewell, W. A., Trustee
Hibbert, R. E., Agent
Hilburn, C. A.
Hinton, Charles A.
Hinton Producing Company
A. J. Hodges Industries Inc.
Hodges, R. M.
Mrs. Luna T. Holcomb
Hollandsworth, G. J.
Hollandsworth and Travis
Holleman, Jeanne Washburn
Home-Stake Production Company
Hood, F. M.
Hooper, S. J.
Houston Oil & Minerals Corp.
J. M. Huber Corporation
Huffines, V. R.
Dudley, J. Hughes
Hughey, W. R.
Humble Oil and Refining Company
Hunt, H. L.
Haroldsen L. Hunt, Jr., Trust Estate
Hassie Hunt Trust
Hunt Industries
Lamar Hunt
Lamar Hunt Trust Estate
Hunt, Nelson Bunker Trust Estate
Hunt Oil Company
Hunt Petroleum Corporation
William Herbert Hunt Trust Estate
The Hunter Company, Inc.
Hunter, James A.
Hurley Oil and Gas Company
Hutton, H. L.
Ben C. Hyde, Jr.
Hynson, R. C.
Imperial Production Corporation
Inabnet, W. B.
Inger, Henry S.
Ingersoll Power & Fabricating Company Inc.
International Helium Inc.
Investors Oil and Gas Inc.
Investors Royalty Company, Inc.
Jabco Inc.
Jackson, J. E.
Jackson, J. E. Inc.
L. B. Jackson Company
T. L. James and Company, Inc.
Javelin Oil Company, Inc.
The Jaybird Corporation
Jenkins, Charles L.
Jenkins-Ray Supply
Jennings, R. L. and Clogg, M. d/b/a Jennings and Clogg
Jernigan, J. E. & Morgan M. V. d/b/a Jernigan and Morgan Oil Company
Jernigan and Morgan Transmission Company
Johnson, E. Lyle
Johnson, Gilbert S.
Johnson, Howard C.
Jones, Carroll G.
Jones, James Marshall

Jones, Joseph M.
L. E. Jones Drilling Company
Jones, O'Brien Inc.
Jones, Shelburne and Pellow Oil
Jorden, Jack C., Jr.
Josaline Production Company
Jowoco, Inc.
Karll, R. P.
K. B. Compression Company, Inc.
Keener Oil Company
Kemp, James E.
Kenyon, Clarence
Kerr-McGee Corporation
Ketchum, Ralph F. d/b/a Ketchum Oil Company
Killingsworth, S. H.
King, J. D.
King, Liberta Investments
King, Robert E.
Kinnebrew, Lee
Kinne, M. L.
Kinsey, Norman V.
Kirby Petroleum Company
Kirkpatrick Oil and Gas Company
Kubler, E. C., Jr.
R. Lacy, Inc.
Ladner, Heber
Laffoon Oil Company
La Gloria Oil and Gas Company
P. G. Lake, Inc.
William H. Lambdin
The Lancer Corporation
Landa Oil Company
Langford Drilling Company
Lankford, K. D., Jr.
Larco Drilling Company
Lario Oil and Gas Company
Larson, Perry E. and Max L. Thomas
Larue, Fred d/b/a Larue-Smith Prod. Co.
Latham Joe
Latham Management Company, Inc.
Latimer, D. C.
Lechnar and Hubbard
Le Cuno Oil Corp.
Lee Drilling Company
Lee, R. A. and Ladner, H. L.
Lee, Robert A.
Le Gendre, P. G.
Lemon, I. M., Mrs.
Lerner, W. Zolley d/b/a Ko-Ler Oil Company
Lewis, Ethel May Neel
Lillystrand, T. O., Jr.
The Lincoln Converse Company
Little, Quintin
Livingston Oil Company
Lomac Drilling Company
London Gas Company
Lone Star Producing Company
Longhorn Production Company
Lou-Ala Development Corporation, Inc.
Lubell Oil Company
Lynn Drilling Company
Lyons, C. H., Jr.
Lyons and Logan
Lyons, C. H., Sr.
McAlster Fuel Company
W. C. McBride, Inc.
McCain, M. F.
McCalman Drilling Company, Inc.
McCamic, Charles
McCausland, Oscar B.
McCommons Oil Company
McCommons, William E. d/b/a McCommons Exploration Company
McConnell, D. B.
McCord, Charles T., Jr. d/b/a McCord Oil Company

McCulloch Oil Corporation of California
McGuire, T. W.
McKnight, Peyton, Jr.
McLemore, B. Regan
McMahon, C. L., Jr.
McMillin, Frank E.
McMurrey, Jim, Estate
McNeish, George R.
McRae, Ethel C.
M & M Producing Company
Machin Oil Ltd.
Mack Oil Company
Mackey, Earl T.
Madole, J. D.
Magna Oil Corporation
MaGuire, Russell, Estate of
Malernee Oil Company

Manziel, Bobby
Manziel, Dorothy N.
Mapco Production Company
Marathon Oil Company
Marcus, Earl
Marks, E. W., Sr.
Marr, M. H.
Marshall Exploration Company Inc.
C. F. Martin Inc.
W. T. Massey and Harry A. Moore d/b/a Massey & Moore
Maynard Oil Company
Mayronne, R. W., Jr. d/b/a Riverside Oil Company
Medallion Oil Company
Menefee, J. M.
Mercury Drilling Company
Merrick, Ward S., Jr.
Mesa Petroleum Company
Midhurst Oil Corporation
Midway Oil Company
Midwest Oil Corporation
Miles Kimball Company
Miller, Paul L.
Miss-Tex Oil Producers
Mitchell, George and Associates, Inc.
Mitchell, W. H.
Mobil Oil Corporation
Moffatt, Robert J.
Moffitt, Mrs. Tom J.
Moise, Mrs. Leah H.
W. A. Moncrief
Monla Gas Company Inc.
Monroe Gas System Inc.
Monsanto Company
Morgan Brothers
Morgan, Dave
Morgan, J. A.
Morris, C. L.
Morris, P. D.
Mortimer, Mrs. Betty D.
Mosbacher, Robert
Moss, H. S.
Murphy, Charles H., Jr.
Murphy Oil Company of Oklahoma Inc.
Murphy Oil Corporation
Muslow, James
Mutual Investment Company
Myers, Sidney G., Jr.
Nafco Oil and Gas Company Inc.
National Bank of Commerce of Houston
National Oil Company Inc.
Natol Petroleum Corporation
Neal, T. J.
Nemours Corporation
Neustadt, Doris W.
Newton Naval Stores Company, Inc.

Nichols, Irl A.
Nobles, Eulalie M.
Nolan, William C. and T. M.
North Central Oil Corporation
Norton Oil Company Inc.
Norville Oil Company Inc.
Nowery, James R.
O'Boyle, John W.
O'Boyle, Kathleen, Trust No. 2
O'Rourke, D. F.
Occidental Petroleum Corporation
OK and B Drilling Company
Oklahoma Natural Gas Company
Oliver, Rees R.
Oliphant, A. G.
Olympic Oil Company
Onstott, L. J. d/b/a Progress Petroleum Products
Orr, B. B.
Osborn, Jewel
Osborn, W. B., Jr.
W. B. Osborn, Jr., Executor The Estate of W. B. Osborn, Sr.
Owen, K. D.
Oxley, John C.
Ozark Gas Corporation
P. S. and G., Inc.
Page, Wiley
Palmer, Milo T.
Pan American Petroleum Corporation
Patterson, H. I. and Williams, R. E.
Penn, G. E.
Perkins, Elizabeth
Perkins, J. R.
Permian Corporation
Perritt, H. W.
W. C. Perryman
Petroleum Corporation of Texas
Phillips, B. F., Estate of
Phillips, Jack L.
Phillips, Leonard W.

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Phillips, Loyce
Phillips, O. A., Estate of
Phillips Petroleum Company
Pickens, W. L.
Pioneer Oil and Gas Company Inc.
Pioneer Oil Investment Company
Placid Oil Company
Porter, L. B.
Potter, Tom
Powers, M. F. Estate
Prentice, Paul R.
Prentiss, W. P.
Price, Jack E.
Proctor, Douglas E., Jr.
Pruet, Chesley
Quisenberry, W. Y.
Radford, C. H.
Raigorodsky, Paul M.
Ray, Lucie L.
Raymond Oil Company, Inc.
Read, Paul L.
Reed, M. T.
Republic Royalty Company
Reserve Oil and Gas Company
Reynolds Mining Corporation
Rhoades Oil Company
Richardson Oils, Inc.
Richenthal, Arthur
C. R. Ridgway
Ridgway Management, Inc.
Rimrock Tidelands Inc.
Rio Rojo Gathering System Inc.
River Corporation
Robbins, J. C., Jr.
Robbins Petroleum Corporation

Roberts, J. I.
Roberts and Murphy, Inc.
Robinson, L. L.
Robinson & Marshall Drilling Company
Rogers, Hellena Fox Wright
Roper, Frank C.
Rorem, S. D.
Ross Production Company
Ross, R. M.
Wilhelmin du P. Ross
Rougon, Dr. and Mrs. A. L.
Rowan, J. Mike
Rozeman, A. M.
Rudco Oil and Gas Company
Rudman, Rose
Rushing, J. S.
Ryan, Fred H.
Ryan, P. H.
Ryan, Ray
Samedan Oil Corporation
Martin A. Samuelson
Sanders, Nell E.
Sanford, John T.
Schafer Drilling Company
Schober, Henry I.
Scott, Francis W.
Joseph E. Seagram and Sons, Inc. d/b/a Texas Pacific Oil Company
Sells Petroleum Inc.
Sellwood and Myers
Service Gas Products Company
Sesco Production Company
Shadid, Fred V.
Shalett, H. T. and Crow, David
Shear, Warren
Shell Oil Company
Shields, Jay M.
Sho Van Gas Producing Company
R. H. Siegfried Inc.
Siesta Oil and Exploration Company, Inc.
Signal Oil & Gas Company
Simmons, D. J. d/b/a Farrell and Company of Louisiana
Simmons, Jay
Simmons, Maxwell D.
Sinclair Oil Corporation
Skeeters, A. Z.
Skelly Oil Company
Skelton, D. W.
Sklar, Sam
Slack, Bob B.
Smith, Douglas V.
Smith, E. D.
Smith, H. S.
Smith, J. J.
Smith, L. E.
Smith Operating & Management Company
Smith, P. E.
Smith, R. E.
Smith, Walter R.
Snee, William E.
Sohio Petroleum Company

Sohoma Natural Gas Company, Inc.
South Central Natural Gas Corporation
Southern Union Production Company
Southwest Gas Producing Company, Inc.
Stack, J. E., Jr.
R. A. Stacey, Jr.
States Oil Company, Inc.
Stephens Production Company

Stephenson, J. F.
Stewart, Austin E.
D. W. Stewart, Jr., and E. L. Stewart
Strahan Oil and Gas Company, Inc.
Strength, (Mrs.) Janie R.
Harry J. Strief, Estate of
Stringer, Murray D.
Sun Oil Company
Sun Oil Company (DX Division)
Sunset International Petroleum Corporation
The Superior Oil Company
Sutton, Carol Daube
Tacony Company, The
Talbot, C. P.
Tate, Ernest W.
Taubert, J. E.
Tanner, J. W.
Taylor, Mrs. Douglas Havard
Taylor, McCleland
Teekel, Lloyd G.
Tenneco Oil Company
Texaco Inc.
Texas Gas Exploration Corporation
Texas San Juan Oil Corporation
Thomas, Evan A.
Thomason, D.
D. Thomason Production Company Inc.
Thompson, J. Cleo
Tittle, W. M.
Todd, Dr. John D.
Trahan, J. C.
J. C. Trahan Drilling Contractor Inc.
Trans-State Oil Company, Division of Hess Oil and Chemical Corporation
Trant, Mike
d/b/a Mike Trant Drilling Company
Trant, Sam
Treat, Frank B.
Tri J. Inc.
Trice Production Company
Tuttle, R. M.
d/b/a R. M. Tuttle Pipe Line
Twin Gas Company
Union Oil Company of California
Union Producing Company
Union Texas Petroleum, a Division of Allied Chemical Corporation
Vanson Production Corporation
Vaughn, G. H., Jr. and Jack C.
Vaughn, G. H., Jr.
Vaughn Petroleum Inc., Agent
Vaughey and Vaughey
Venters, Harley E.
Wager, Dan R.
Walker, Keith F.
Walker, Ross
Wannop, Mary Fitts
Warren Petroleum Corporation
Wegmann, W. A.
Westates Petroleum Company
Westheimer Neustadt Corporation
Westland Oil Development Corporation
Wheless Drilling Company
N. H. Wheless Oil Company
Whitaker, Douglas
Fred Whitaker
White, Blanche N.
White, Janet
White, T. J., Jr.
Whitehall Oil Company, Inc.
Whittington Number Five
Wichita River Oil Corporation
Wiederhold, William C., Agent
Williams, Charles K.
Williams, E. B., Jr.
Williams, E. B., Sr.
Williams, George H. and Hill
Williams Pressure Service Company
Williams, Robert Gordon
Wilson, Bruce L.

Wilson, Norton F.
Winwell Inc.
Wise Operating, Inc., of Tyler
Wolfe Drilling Company
Wood Oil Company
Woods, Harold L.
Woods Petroleum Corporation
Worldwide Petroleum Corporation
Worth Drilling Company
Wrather, J. D., Jr.
Wunderlich Development Company
W. R. Yinger
Marshall R. Young Oil Company
Zephyr Drilling Corporation
Zephyr Oil Company

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CHANGES IN NAMES OF RESPONDENTS PREVIOUSLY LISTED

PREVIOUSLY	NOW
J. R. Butler and Company	Skelly Oil Company
Caska Corporation	CRA, Inc.
Coulston Drilling Company	Perriman, W. C.
Crystal Oil and Land Company	Crystal Oil Company
Cyprus Mines Corporation	Skelly Oil Company
Davis, D. D.	Wilson, Alvin
Davis, Waymon L.	Witt Oil Production, Inc.
Gage, Coke L.	Mitchell, George and Associates, Inc.
Pan American Petroleum Corp.	Amoco Production Company
Shadid, Fred V.	Sheets, R. R.
Sinclair Oil Corporation	Atlantic Richfield Company
Smith, E. D.	Smith, Jack H.
Strief, Harry J., Estate of	Strief, Harry and Robert
Union Producing Company	Pennzoil Producing Company

PART II

RESPONDENT PIPELINE PURCHASERS

Arkansas Louisiana Gas Company
Arkansas Oklahoma Gas Corporation
Cimarron Transmission Company
Cities Service Gas Company
El Paso Natural Gas Company
Lone Star Gas Company
Louisiana Nevada Transit Company
Michigan Wisconsin Pipe Line Company
Mid Louisiana Gas Company
(Formerly: Humble Gas Transmission Company)
Mississippi River Transmission Corporation
Natural Gas Pipe Line Company of America
Panhandle Eastern Pipe Line Company
Rio Sabine Incorporated
Southern Natural Gas Company
Tennessee Gas Pipeline Company,
A Division of Tenneco, Inc.
Texas Eastern Transmission Corporation
Texas Gas Transmission Corporation
Trunkline Gas Company
Union Gas System, Incorporated
United Fuel Gas Company
United Gas Pipe Line Company
Valley Gas Transmission Incorporated

PART III

SECTION 4(E) RATE SUSPENSION PROCEEDINGS[1] CONSOLIDATED FOR HEARING WITH AREA RATE PROCEEDING (OTHER SOUTHWEST AREA), DOCKET NO. AR67-1

NAME[2]	DOCKET NOS.
Amerada Hess Corporation	RI65-334
American Petrofina Co. of Texas (Oper.), *et. al.*	RI64-442
Apache Corporation	RI63-332
Arkla Exploration Company	RI64-233, RI64-240, RI64-277, RI66-339.
Ashland Oil & Refining Company, *et. al.*	RI60-288
Atlantic Richfield Company	RI60-231, RI61-172, RI64-256, RI65-28, RI66-166, RI66-345.
Bander, Joe, *et. al.*	RI67-54
Bond, Durbin	G-20184
Borden, S. P.	G-20191
Bracken Oil Company (Oper.), *et. al.*	G-16084
Bridewell, Billy (Oper.), *et. al.*	RI63-241
D. H. Byrd (Oper.)	RI64-203
Cameron, A. A., d/b/a Cameron Oil Company, *et. al.*	RI65-521, RI67-80.
Carter-Jones Drilling Co., Inc. (Oper.), *et. al.*	RI61-546

[1] These proceedings are consolidated only insofar as they pertain to sales in the Other Southwest Area.

[2] This producer designation is for general identification and may not include all of the respondents designated in the respective orders initiating rate suspension porceedings.

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Champlin Petroleum Company	RI63-304
Chevron Oil Company/Western Division	RI63-462
Claiborne Gasoline Company	RI64-260
Cohen, Don (Oper.), *et. al.*	RI64-421
Coles, Marvin J., *et. al.*	RI64-134
Continental Oil Company	G-19734, G-20197, RI60-193, RI60-223, RI61-249, RI63-217, RI63-350, RI63-368, RI64-165, RI64-166, RI64-784, RI67-72.
Continental Oil Co. (Oper.), *et. al.*	RI63-240, RI65-128.
Continental Oil Co. (Oper.), and Clinton Oil Co. (Oper.)	RI65-231
Cox, Edwin L.	RI63-219, RI63-428, RI64-68, RI64-573.
Cyprus Mines Corp. & Skelly Oil Co. (Oper.)	RI64-8
Coastal States Producing Company	RI67-159
Davis, C. D., *et. al.*, and Car-Tex Producing Co., *et. al.*	RI65-374
Draughn, Paul V., Jr.	RI65-424
Draughn, Paul V., Sr.	RI65-422
Dugan, Thomas A.	RI65-600
Ells, H. A., *et. al.*, d/b/a All Star Gas Co. and Signal Oil and Gas Co.	RI63-178
Falcon Seaboard Drilling Co., *et. al.*	RI63-221
Fields, Bert, Jr., *et. al.*	RI64-290
Forest Oil Corporation	RI63-230
Forest Oil Corp. (Oper.), *et. al.*	RI65-125

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Four States Drilling Co., Inc. (Oper.), *et. al.*	G-20081
Gant, Walter H. (Oper.), *et. al.*	RI64-254
General American Oil Co. of Texas	RI63-377, RI65-345.
Getty Oil Company	RI64-726, RI64-762, RI65-129.

Greenville Gasoline Co., Inc. (Oper.)	RI63-275
Gulf Oil Corporation	G-11335, G-13519, G-13581, G-16657, G-19742, G-20560, RI60-214, RI61-169, RI61-212, RI62-114, RI63-148, RI64-198, RI64-231, RI64-247.
Gulf Oil Corp. & Ashland Oil & Refining Company	RI65-599
Hall, Stanton A.	RI65-421
Hamman, Blake (Oper.), *et. al.*	RI64-710
Harper Oil Company (Oper.), *et. al.*	RI63-450, RI65-274.
Hefner Company, The (Oper.), *et. al.* and Sun Oil Co.	RI63-472
Helmerich & Payne Inc. (Oper.), *et. al.*	RI63-445
Home-Stake Production Co. OEA and Wolfe Drilling Co. OEA	RI64-124
Humble Oil and Refining Co. (Oper.), *et. al.*	RI66-24, RI66-279, RI67-108.
Humble Oil and Refining Co. and Texaco Inc.	RI66-149
Hunt, H. L., *et. al.*	RI61-203, RI62-136, RI64-44, RI66-131.
Haroldson L. Hunt, Jr., Tr. Est.	RI66-239, RI67-180.
Hassie Hunt Trust	G-19752, RI61-206, RI63-104, RI64-213, RI65-265, RI67-100.
Hassie Hunt Trust (Oper.), *et. al.*	RI66-130
Lamar Hunt Trust Estate, *et. al.*	RI66-240, RI67-181
Hunt, Nelson Bunker Trust Estate	RI66-241, RI67-182.

Hunt Oil Company	RI63-229, RI66-127, RI66-243, RI67-98, RI67-178, RI67-179.
Hunt Oil Co. (Oper.), *et. al.*	RI66-237, RI66-270.
Hunt Oil Co., *et. al.*	RI66-242
Hunt Petroleum Corporation	RI65-261
Hunt, William Herbert Trust Estate	RI66-238, RI67-183.
Hunter Company, Inc., The	G-19920

Hurley Oil & Gas, *et. al.*	G-16645
Hurley Oil & Gas (Oper.), *et. al.* & Mobil Oil Corporation	RI62-318, RI64-201.
Hyde, Ben C. W., Jr. (Oper.)	RI63-279
T. L. James & Company, Inc., *et. al.*	RI66-172, RI66-173.
Jernigan, J. E. & Morgan, M. V., d/b/a Jernigan & Morgan Oil Company	RI63-233
Jernigan & Morgan Transmission Co.	RI63-234
R. Lacy, Inc., *et. al.*	G-14315
Laffoon Oil Company	RI64-689
Landa Oil Company	G-19028, RI64-730, RI64-740, RI65-397.
Lario Oil & Gas Company	RI64-601
D. C. Latimer	RI61-410
LeCuno Oil Corporation	RI60-459
LeCuno Oil Corp. & Landa Oil Co.	RI61-210
London Gas Co., *et. al.*	RI61-112, RI63-176, RI63-177.
McCommons Oil Company, *et. al.*	RI64-21, RI65-568.

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McCommons, W. E., d/b/a McCommons Exploration Co., *et. al.*	RI63-281
Mack Oil Company	RI64-18
Mapco Production Co. (Oper.), *et. al.*	RI66-20
Marathon Oil Company	RI66-140, RI67-121, RI66-33, RI66-74.
Marathon Oil Company (Oper.), *et. al.*	RI66-19
Marks, E. W., Sr., *et. al.*	RI62-272
Marr, M. H.	RI66-144
C. F. Martin, Inc.	RI65-372
Maynard Oil Company	RI64-288, RI67-17, RI67-18.
Maynard Oil Co. (Oper.), *et. al.*	RI64-287, RI66-10.
Midway Oil Company, *et. al.*	RI64-87
Midwest Oil Corporation	RI64-195
Midwest Oil Corporation (Oper.), *et. al.*	RI64-214
George Mitchell & Associates, Inc., Agent for Ann W. Alexander, Executrix, *et. al.*	RI61-239

Mobil Oil Corporation	RI61-113, RI61-188, RI65-196.
Mobil Oil Corp. (Oper.), *et. al.*	RI61-114, RI64-210, RI65-276, RI66-98.
Mortimer, Mrs. Betty D., *et. al.*	G-20194
Murphy Oil Corporation, *et. al.*	RI61-145
Murphy Oil Corporation	RI61-146
Newton Naval Stores Co., Inc.	RI65-346
North Central Oil Corporation *et. al.*	G-19026

Norville Oil Company, Inc.	RI64-19
Pan American Petroleum Corp.	G-13516, G-16629, G-17058, G-19641, G-19765, RI61-167, RI61-192, RI62-151, RI63-81, RI63-138, RI63-231, RI64-222, RI64-231, RI65-178, RI65-277, RI65-294, RI66-129.
Perkins, Elizabeth, *et. al.*	RI64-114
Phillips Petroleum Company	G-12283, G-16112, G-16113, RI60-257, RI63-394, RI64-619, RI65-577, RI66-324.
Phillips Petroleum Co. (Oper.), *et. al.*	RI61-284, RI67-173.
Phillips Petroleum Co. and Moran Pipe and Supply Company, Inc.	RI65-127
Pioneer Oil & Gas Co., Inc., *et. al.*	G-20195, RI61-51.
Placid Oil Co. (Oper.), *et. al.*	G-17423, G-19767, RI61-176, RI61-213, RI62-104, RI64-202, G-15370.
Ridgway, C.K.&W.B.	G-19932
Ridgway Management, Inc.	G-20068
Rimrock Tidelands, Inc., *et. al.*	G-15073
Robbins, J. C., Jr.	RI63-475
Robbins Petroleum Corp., Pan American Petroleum Corp., OEA, and Amerada Petroleum Corporation	RI63-476
Roper, Frank C.	RI60-389
Ross, R. M.	RI65-318
Rowan, J. Mike (Oper.), *et. al.*	RI63-293
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The Superior Oil Co. (Nevada) and James W. Harris	G-14106

The Superior Oil Company and Gas Rock Corporation	G-18694
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Billy Bridewell (Operator), *et. al.*	RI68-512
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Tenneco Oil Company and Continental Oil Company	RI64-70
Texaco, Inc. (Operator), *et. al.*	RI67-59, RI68-19, RI68-609, RI68-647, RI69-580, RI69-755
Texaco Inc., *et. al.*	RI71-1121, RI72-25
Texaco Inc.	RI67-58, RI67-242, RI67-342, RI68-16, RI68-122, RI68-221, RI68-607, RI68-649, RI69-16, RI69-424, RI69-581, RI69-822, RI70-42, RI70-408, RI70-716, RI70-1161, RI70-1638, RI70-1639, RI71-1023, RI71-1040, RI71-1078

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Texas Pacific Oil Company, Inc. (Operator), *et. al.*	RI68-659, RI69-36
Texas Pacific Oil Company, Inc.	RI68-681, RI69-20, RI69-43, RI71-1105
J. Cleo Thompson (Operator), *et. al.*	RI70-842
Tonkawa Gas Processing Company	RI71-912
J. C. Trahan Drilling Contractors, Inc. (Operator), *et. al.*	RI71-67
J. C. Trahan Drilling Contractors, Inc.	RI67-295, RI68-397
Twin Gas Company (Operator) and Signal Oil and Gas Company (Operator)	RI68-646
Union Oil Company of California (Operator), *et. al.*	RI68-294
Union Oil Company of California	RI67-248, RI68-293, RI68-489, RI68-553, RI68-664, RI69-68, RI69-770, RI70-1311, RI71-1022
Union Texas Petroleum, A Division of Allied Chemical Corporation (Operator), *et. al.*	RI68-275, RI69-758
Union Texas Petroleum, A Division of Allied Chemical Corporation, *et. al.*	RI70-513, RI71-872
Union Texas Petroleum, A Division of Allied Chemical Corporation	RI68-305, RI71-1050, RI71-1120
G. H. Vaughn, Jr. and Jack C. Vaughn (Operator), *et. al.*	RI68-300
G. L. Vinson	RI71-822
Warren Petroleum Corporation (Operator)	RI69-14
Warren Petroleum Corporation	RI70-850, RI70-851, RI71-669, RI71-1130
Arthur J. Wessely	RI71-447

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Wheless Drilling Company (Operator), *et. al.*	RI68-368, RI71-312
White Shield Oil and Gas Corporation (Operator), *et. al.*	RI70-1501
Whittington Oil Company, Inc. (Operator), *et. al.*	RI70-233
Alvin Wilson (Operator), *et. al.* and Dakota Mining and Development Corporation	RI70-685
Bruce L. Wilson, *et. al.*	RI71-988
Woods Petroleum Company	RI67-283
Jack D. Wrather, Jr.	RI69-86

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ADDENDUM

(Rate Increases Suspended Since August 12, 1971)

Arkla Exploration Company	RI72-89
Atlantic Richfield Company	RI71-47, RI72-49
Continental Oil Company	RI72-63
Getty Oil Company	RI72-114
Humble Oil and Refining Company	RI72-98, RI72-115
Hassie Hunt Trust	RI72-99
H. L. Hunt	RI72-97
Hunt Oil Company	RI72-100
James A. Hunter	RI72-88
Marathon Oil Company	RI72-95
Miles Kimball Company	RI72-61
Mobil Oil Corporation	RI72-94
Morgan Brothers	RI72-59
Murphy Oil Corporation	RI72-45, RI72-48
Pennzoil Producing Company	RI72-84
Phillips Petroleum Company	RI72-62, RI72-90
Placid Oil Company	RI72-96
Skelly Oil Company	RI72-116
Sohio Petroleum Company	RI72-117
Southwest Gas Producing Company, Inc.	RI72-50
Suburban Propane Gas Corporation	RI72-46
Sun Oil Company	RI72-101
Tenneco Oil Company	RI72-60
Union Oil Company of California	RI72-83

PART V

INTERVENORS

American Public Gas Association consisting of gas distributors within the States of Alabama, Arkansas, Colorado, Connecticut, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas and Washington.
Atlanta Gas Light Company
The Berkshire Gas Company
Boston Gas Company
Bristol and Warren Gas Company
Brockton Taunton Gas Company
Brooklyn Union Gas Company
Buzzards Bay Gas Company
Cambridge Gas Company
Central Hudson Gas and Electric Corporation
Central Massachusetts Gas Company
City Group Gas Defense Association consisting of the Kansas cities of Altamont, Atchison, Chanute, Countryside, Erie, Fairway, Girard, Grenola, Howard, Iola, Leavenworth, Neodesha and Prince Village; and the Missouri Cities of Aurora, Carl Junction, Carthage, Independence, Joplin, Kansas City, Marshall, Monett, Mt. Vernon, Neosho, Nevada, Oronogo, St. Joseph, Springfield, Waverly and Webb City.
City of Chicago
City of Holyoke, Massachusetts Gas and Electric Department
City of Los Angeles
City of Norwich, Department of Public Utilities

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City of Westfield Gas and Electric Light Department
Concord Natural Gas Corporation
The Connecticut Gas Company
Consolidated Edison Company of New York, Inc.
Consolidated Gas Supply Corporation
The East Ohio Gas Company
Elizabethtown Gas Company
Fall River Gas Company
Fitchburg Gas and Electric Light Company
Gas Service, Inc.
The Greenwich Gas Company
The Hartford Electric Light Company
The Hartford Gas Company
Haverhill Gas Company
Independent Petroleum Association of America
Iowa Electric Light and Power Company

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Humble Oil & Refining Co. (continued):
The California Co., a Division of Chevron Oil Co.
Cities Service Co.
Cities Service Oil Co.
Continental Oil Co.
General American Oil Co. of Texas
Getty Oil Co.
Gulf Oil Corp.
Marathon Oil Co.
Midhurst Oil Corp.
Midwest Oil Corp.
Murphy Oil Corp.
Pan American Petroleum Corp.

Shell Oil Co.
Signal Oil & Gas Co.
Service Gas Products Co.
Sohio Petroleum Co.
Southwest Gas Producing Co., Inc.
Sun Oil Co.
Tenneco Oil Co.
Texaco Inc.
Union Producing Co.
Warren Petroleum Corp.

Hunt Oil Co.:
H. L. Hunt
Haroldson L. Hunt, Jr., Trust Estate
Hassie Hunt Trust
Hunt Industries
Hunt Petroleum Corp.
William Herbert Hunt Trust Estate
Lamar Hunt
Lamar Hunt Trust Estate
Nelson Bunker Hunt Trust Estate
Placid Oil Co.

Oklahoma Independent Petroleum Association
Pan American Petroleum Corp.
Phillips Petroleum Co. & Mobil Oil Corp.

Pipeline Purchaser Group:
Cities Service Gas Co.
Lone Star Gas Co.
Natural Gas Pipeline Co. of America
Panhandle Eastern Pipe Line Co.
Southern Natural Gas Co.
Tennessee Gas Pipeline Co.
Texas Eastern Transmission Corp.
Texas Gas Transmission Corp.
Trunkline Gas Co.
United Gas Pipe Line Co.

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Superior Oil Co.
United Distribution Companies:
American Natural Gas System
Michigan Consolidated Gas Co.
Wisconsin Gas Co.
Central Illinois Light Co.
Central Illinois Public Service Co.
Citizens Gas & Coke Utility
Columbia Gas System
Columbia Gas of Kentucky, Inc.
Columbia Gas of Maryland, Inc.
Columbia Gas of New York, Inc.
Columbia Gas of Ohio, Inc.
Columbia Gas of Pennsylvania, Inc.
Ohio Valley Gas Co.
Virginia Gas Distribution Co.
Consolidated Natural Gas System
Consolidated Gas Supply Corp.
The East Ohio Gas Co.
Lake Shore Pipe Line Co.
The Peoples Natural Gas Co.
The River Gas Co.
West Ohio Gas Co.
Consumers Power Co.
The Dayton Power & Light Co.
Equitable Gas Co.
Illinois Power Co.
Iowa-Illinois Gas & Electric Co.
Michigan Gas Utilities Co.
Mississippi Valley Gas Co.

National Fuel Gas System
Iroquois Gas Corp.
Pennsylvania Gas Co.
United Natural Gas Co.
Northern Illinois Gas Co.
Orange & Rockland Utilities, Inc.
The Peoples Gas System
North Shore Gas Co.
The Peoples Gas Light & Coke Co.
South Carolina Electric & Gas Co.
The State of Texas
The Commission Staff

PART VI

PARTIES FILING BRIEFS ON EXCEPTIONS[1]

Associated Gas Distributors
Atlanta Gas Light Co.
The Berkshire Gas Co., Boston Gas Co., Bristol & Warren Gas Co., Brockton Taunton Gas Co., Buzzards Bay Gas Co., Cambridge Gas Co., Central Massachusetts Gas Co., City of Holyoke, Massachusetts Gas & Electric Dept., City of Norwich—Dept. of Public Utilities, City of Westfield Gas & Electric Light Dept., Concord Natural Gas Corp., The Connecticut Gas Co., Connecticut Natural Gas Corp., Fall River Gas Co., Fitchburg Gas & Electric Light Co., Gas Service Inc., The Greenwich Gas Co., The Hartford Electric Light Co., Haverhill Gas Co., Lawrence Gas Co., Lowell Gas Co., Lynn Gas Co., Manchester Gas Co., Mystic Valley Gas Co., New Bedford Gas & Edison Light Co., The Newport Gas Light Co., Northampton Gas Light Co., North Attleboro Gas Co., North Shore Gas Co., Norwood Gas Co., The Pequot Gas Co., South County Gas Co., Southern Connecticut Gas Co., Springfield Gas Light Co., Tiverton Gas Co., Valley Gas Co., Wachusett Gas Co., and Worcester Gas Light Co. (jointly)
Central Hudson Gas & Electric Corp.
Consolidated Edison Co. of New York, Inc.
Elizabethtown Gas Co.
Long Island Lighting Co.

[1] Names are as stated in filed Briefs on Exceptions.

New Jersey Natural Gas Co.
New York State Electric & Gas Corp.
Niagara Mohawk Power Corp.
Philadelphia Electric Co.
Philadelphia Gas Works, Division of UGI Corp.
Piedmont Natural Gas Co., Inc.
Public Service Co. of North Carolina
Public Service Electric & Gas Co.
Rochester Gas & Electric Corp.
South Jersey Gas Co.
UGI Corp.
Washington Gas Light Co.
George Mitchell & Associates, Inc.
Humble Oil & Refining Co.:
Amerada Hess Corp.
Ashland Oil & Refining Co.
Atlantic Richfield Co.

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Lake Shore Pipeline Company
Lawrence Gas Company
Long Island Lighting Company
Lowell Gas Company
Lynn Gas Company
Manchester Gas Company
Michigan Gas Utilities Company
Michigan Public Service Commission
Mystic Valley Gas Company
New Bedford Gas and Edison Light Company
The New Britain Gas Light Company
New Jersey Natural Gas Company
The Newport Gas Light Company
New York State Electric and Gas Corporation

Niagara Mohawk Power Corporation
Northampton Gas Light Company
North Attleboro Gas Company
Northern Illinois Gas Company
Northern Indiana Public Service Company
North Shore Gas Company
Norwood Gas Company
Oklahoma Independent Petroleum Association
Orange and Rockland Utilities, Inc.
Pacific Gas and Electric Company
Pacific Lighting Service and Supply Company
Pennsylvania Public Utilities Commission
The Peoples Natural Gas Company
The People of the State of California and the Public Utilities Commission of the State of California.
The Pequot Gas Company
Philadelphia Electric Company
Piedmont Natural Gas Company, Inc.
Providence Gas Company
Public Service Commission of the State of New York
Public Service Commission of Wisconsin
The River Gas Company
Rochester Gas and Electric Corporation
San Diego Gas and Electric Company
South County Gas Company
Southern California Gas Company
The Southern Connecticut Gas Company
Southern Counties Gas Company of California
South Jersey Gas Company
Springfield Gas Light Company
The State of Texas and the Railroad Commission of Texas

Texas Independent Producers and Royalty Owners Association
Tiverton Gas Company
UGI Corporation
Valley Gas Company
Wachusett Gas Company
Washington Gas Light Company
Worcester Gas Light Company

APPENDIX B

RESERVE AND PRODUCTION DATA
Other Southwest Area

(Trillions of Cublic Feet)

Year	Form 15 Data: Annual Production	Form 15 Data: Reserve Additions	Year-End Reserves	Dedicated Reserves to Production Ratio	Findings to Production Ratio
1964	1.265	1.634	13.971	11.0	1.29
1965	1.221	0.708	13.459	11.0	0.58
1966	1,246	1.446	13.659	11.0	1.16
1967	1.186	0.952	13.425	11.3	0.80
1968	1.214	0.319	12.530	10.3	0.26
1969	1.210	0.479	11.799	9.8	0.40
1970	1.179	0.029	10.719	9.1	0.02

Year	AGA Data: Annual Production	AGA Data: Reserve Additions	Year-End Reserves	Proved Reserves to Production Ratio	Findings to Production Ratio
1964	2.203	2.866	27.460	12.5	1.30
1965	2.172	2.258	27.554	12.7	1.04
1966	2.285	2.093	27.406	12.0	0.92
1967	2.186	1.111	26.404	12.1	0.51
1968	2.103	—0.084[a]	24.236	11.5	—0.04[a]
1969	2.152	1.122	23.236	10.8	0.52
1970	2.134	1.036	22.142	10.4	0.48

Sources: FPC Form 15 Annual Reports and the American Gas Association Annual Reports, Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada.

[a] Reserve additions and ratios of less than zero caused by downward revisions of previous estimates of reserves discovered as estimated in earlier years.

RESERVE AND PRODUCTION DATA
U.S. Excluding Alaska

(Trillions of Cubic Feet)

	Form 15 Data				
Year	Annual Production	Reserve Additions	Year-End Reserves	Dedicated Reserves to Production Ratio	Findings to Production Ratio
1964	10.3	10.7	192.5	18.7	1.04
1965	10.5	12.8	194.8	18.6	1.22
1966	11.3	15.0	198.4	17.6	1.33
1967	12.0	15.7	202.1	16.8	1.31
1968	12.8	9.4	198.7	15.5	0.73
1969	13.7	6.4	191.5	14.0	0.47
1970	14.1	3.7*	173.7	12.3	—0.26*

	AGA Data				
Year	Annual Production	Reserve Additions	Year-End Reserves	Proved Reserves to Production Ratio	Findings to Production Ratio
1964	15.3	20.1	279.4	18.2	1.31
1965	16.2	21.2	284.5	17.5	1.31
1966	17.5	19.2	186.4	16.4	1.10
1967	18.4	21.1	289.3	15.8	1.15
1968	19.3	12.0	282.1	14.6	0.62
1969	20.6	8.3	269.9	13.1	0.40
1970	21.8	11.1	259.6	11.9	0.51

Sources: FPC Form 15 Annual Reports and the American Gas Association Annual Reports, Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada.

* Reserve additions and ratios of less than zero caused by downward revisions of previous estimates of reserves discovered as estimated in earlier years.

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APPENDIX C

Summary of Revenue Received in Other Southwest Area for Gas Purchased by Interstate Pipelines

The sources of this information are the F.P.C. Form 2's, Accounts 800, 801 and 802 filed by interstate pipelines with this Commission. These reports are for sales at wellhead, field and tailgate.

The amounts shown herein are the average unit prices paid during the report year.

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MISSISSIPPI

Volume and Percent of Volume Purchased at 1¢ Price Intervals
(Interstate Purchases From Producers With
Jurisdictional Sales Over 10 Million Mcf)
(Volume @ Rates @ 14.73 Psia)

Volume (Mcf)	1969	1968	1967	1966	1965	1964
24 - 24.999	-	-	18,490,808	-	-	-
23 - 23.999	44,687,866	40,864,419	24,862,780	35,062,299	20,991,305	16,260,907
22 - 22.999	446,998	602,977	1,657,701	2,475,267	5,252,904	24,494,861
21 - 21.999	6,824,729	6,869,144	12,235,696	3,711,410	6,551,677	11,132,575
20 - 20.999	15,842,011	15,421,152	7,411,819	17,843,378	6,934,647	8,333,024
19 - 19.999	12,740,230	14,186,183	17,056,727	20,330,651	40,044,682	24,509,799
18 - 18.999	2,971,367	2,737,356	931,327	503,000	111,083	7,023,712
17 - 17.999	2,152,117	6,230,484	2,825,571	2,869,479	3,640,678	11,099,010
16 - 16.999	21,674,450	18,648,789	14,390,255	16,185,946	15,775,643	14,793,622
15 - 15.999	949,433	1,039,988	8,276,131	7,492,262	111,083	-
14 - 14.999	20,982,766	18,297,251	16,998,201	14,629,924	13,745,807	91,365
13 - 13.999	362,736	329,962	1,299,315	1,172,190	1,691,479	1,533,641
12 - 12.999	-	-	-	-	-	-
11 - 11.999	-	-	-	-	-	-
10 - 10.999	-	-	-	-	-	1,963,204
9 - 9.999	-	-	-	-	-	-
Below 9.000	-	-	-	-	-	-
TOTAL	129,634,363	125,629,330	128,636,331	132,269,766	114,339,909	121,195,720
Percent of Volume (%)						
24 - 24.999	-	-	-	-	-	-
23 - 23.999	34.47	32.63	14.60	26.68	18.01	13.42
22 - 22.999	.34	.48	19.63	2.02	4.59	20.21
21 - 21.999	5.27	5.49	2.31	3.09	5.73	9.19
20 - 20.999	12.22	12.31	9.66	14.59	6.07	6.88
19 - 19.999	9.83	11.33	5.85	16.63	35.02	20.22
18 - 18.999	2.29	2.19	13.47	.41	.10	5.80
17 - 17.999	1.66	4.98	.74	2.35	3.18	9.12
16 - 16.999	16.72	14.89	2.23	13.24	13.80	12.21
15 - 15.999	.73	.83	11.52	6.13	-	-
14 - 14.999	16.19	14.61	6.54	11.96	12.02	.07
13 - 13.999	.28	.26	13.42	.96	1.48	1.26
12 - 12.999	-	-	1.03	-	-	-
11 - 11.999	-	-	-	-	-	-
10 - 10.999	-	-	-	-	-	-
9 - 9.999	-	-	-	-	-	1.62
Below 9.000	-	-	-	-	-	-
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00

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EAST LOUISIANA

Volume (bbl)	1959	1960	1961	1962	1963	1964
24 - 24,999	-	-	-	-	-	-
23 - 23,999	-	-	-	-	-	-
22 - 22,999	-	-	-	-	-	-
21 - 21,999	-	-	-	-	-	-
20 - 20,999	-	-	-	-	-	-
19 - 19,999	-	-	-	-	-	-
18 - 18,999	-	-	-	-	-	-
17 - 17,999	-	-	-	-	-	-
16 - 16,999	-	-	-	-	-	-
15 - 15,999	-	-	-	-	-	-
14 - 14,999	-	-	-	-	-	-
13 - 13,999	-	-	-	-	-	-
12 - 12,999	-	-	-	-	-	-
11 - 11,999	-	-	-	-	-	-
10 - 10,999	-	-	-	-	-	-
Below 9,000	-	-	-	-	-	-
TOTAL	196,264,223	182,192,210	185,464,105	187,038,070	191,651,160	215,079,137
Percent of Volume (%)						
24 - 24,999	-	-	-	-	-	-
23 - 23,999	-	-	-	-	-	-
22 - 22,999	-	-	-	-	-	-
21 - 21,999	-	.11	.35	.20	.31	.01
20 - 20,999	1.87	2.13	.31	.29	.05	.01
19 - 19,999	1.04	.26	10.04	8.43	.18	6.69
18 - 18,999	18.77	12.48	17.36	14.99	7.09	9.40
17 - 17,999	8.17	15.18	13.43	17.55	10.62	16.36
16 - 16,999	9.76	9.85	8.79	11.04	21.58	6.14
15 - 15,999	6.63	7.63	8.56	6.77	2.85	18.58
14 - 14,999	6.27	5.54	21.73	7.43	17.99	9.14
13 - 13,999	34.05	31.39	10.17	21.76	9.14	9.61
12 - 12,999	11.92	8.55	1.40	1.10	19.21	11.58
11 - 11,999	.44	3.27	3.67	3.93	1.28	3.84
10 - 10,999	.16	.97	.20	.01	.01	.01
Below 9,000	-	.00	.01	.01	.01	.01
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00

Value	1962	1964	1962r	1966	1965	1964
24,999						43,849
23,999						61,318
22,999						-
21,999						2,410,122
20,999						22,325,036
19,999	27,972	110,112	98,384	95,594	96,251	60,405,061
18,999	103,303	3,778,110	3,491,918	2,726,287	1,399,347	919,375
17,999	2,676,254	2,152,300	51,677,345	64,230,287	63,491,513	25,110,136
16,999	60,994,251	61,994,847	18,245,653	12,564,440	21,941,815	23,420,671
15,999	5,673,234	16,985,493	20,817,991	21,212,741	25,642,326	54,609,788
14,999	24,294,008	25,995,266	2,774,065	965,931	1,197,106	728,727
13,999	23,189,534	3,091,638	38,096,475	21,224,314	23,465,666	-
12,999	23,443,159	22,416,493	27,282,762	48,126,805	49,912,799	-
11,999	433,419	16,709,972	-	418,004	691,151	-
10,999	-	-	-	-	-	-
9,999	-	-	-	-	-	-
Below 9,000	-	-	-	-	-	-
TOTAL	148,244,917	153,208,611	164,444,633	171,544,103	185,797,914	190,095,113
Percent of Value						
24,999						.02
23,999						.03
22,999						-
21,999						1.27
20,999	.02	.07	.06	.06	.05	11.73
19,999	.07	1.16	2.13	1.59	.76	31.78
18,999	1.80	2.41	32.63	37.44	34.18	-
17,999	5.28	1.41	11.09	7.32	11.81	12.84
16,999	40.67	40.46	12.66	12.37	12.73	12.33
15,999	3.83	11.08	1.69	.76	.69	28.76
14,999	16.39	16.96	21.16	12.36	12.64	.38
13,999	15.64	2.02	16.99	28.06	24.67	-
12,999	15.81	14.63	-	.24	.34	-
11,999	.29	12.21	-	-	-	-
10,999	-	-	-	-	-	-
9,999	-	-	-	-	-	-
Below 9,000	-	-	-	-	-	-
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00

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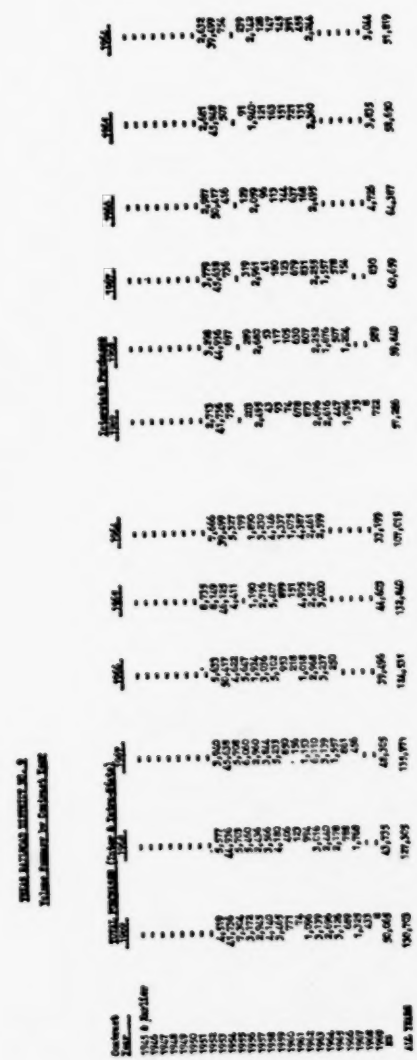
Values	1969	1968	1967	1966	1965	1964
24 - 24.999	-	-	-	-	-	-
23 - 23.999	-	-	-	-	-	-
22 - 22.999	-	-	-	-	-	-
21 - 21.999	-	-	-	-	-	-
20 - 20.999	-	-	113,720	-	-	31,201,651
19 - 19.999	1,061,094	189,514	-	-	-	34,395,098
18 - 18.999	21,676,434	870,433	5,117,777	2,384,103	15,772,163	1,138,103
17 - 17.999	43,213,777	20,728,430	67,306,363	63,456,773	102,369,243	43,473,962
16 - 16.999	153,813,567	79,280,962	44,482,501	46,567,600	8,578,648	388,167
15 - 15.999	122,331	28,754,434	-	10,208,126	831,778	3,000,167
14 - 14.999	1,155,438	-	6,369,699	4,709,279	2,710,991	630,110
13 - 13.999	4,723,524	9,113,192	1,907,322	2,335,249	7,249,280	4,512,504
12 - 12.999	3,468,220	-	1,977,276	7,779,143	-	4,653,498
11 - 11.999	3,441,742	5,614,286	1,779,143	289,134	229,111	-
10 - 10.999	-	-	-	-	-	2,685,644
9 - 9.999	-	-	-	-	-	-
Below 9.000	-	-	-	-	-	-
TOTAL	200,255,299	145,476,845	132,116,999	137,997,041	136,465,702	166,071,139

Percent of Values	1969	1968	1967	1966	1965	1964
24 - 24.999	-	-	-	-	-	-
23 - 23.999	-	-	-	-	-	-
22 - 22.999	-	-	-	-	-	-
21 - 21.999	-	-	-	-	-	-
20 - 20.999	-	-	.09	-	-	18.79
19 - 19.999	.53	.13	-	-	-	20.71
18 - 18.999	10.72	.62	3.87	1.67	11.74	.68
17 - 17.999	21.10	14.55	47.93	46.00	74.99	26.16
16 - 16.999	62.16	54.18	33.70	33.71	7.54	1.92
15 - 15.999	.06	19.76	-	7.34	.76	.16
14 - 14.999	.57	-	4.82	3.41	2.00	.10
13 - 13.999	2.33	6.26	1.44	1.69	5.31	.28
12 - 12.999	1.73	-	1.47	5.64	2.28	2.81
11 - 11.999	1.60	3.86	4.30	-	.17	2.59
10 - 10.999	-	-	.09	-	-	-
9 - 9.999	-	-	-	-	-	-
Below 9.000	-	-	-	-	-	-
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00

TEXAS RAILROAD DISTRICT NO. 3

Volume	1962	1964	1957	1956	1955	1954
24 - 24.999						
23 - 23.999						
22 - 22.999						
21 - 21.999						
20 - 20.999						
19 - 19.999						
18 - 18.999						
17 - 17.999						
16 - 16.999	687,027	691,719	869,133	969,774	930,614	66,132
15 - 15.999	133,424	139,638	2,888,487	3,101,691	133,915	1,180,253
14 - 14.999	31,395,030	6,617,305	4,328,774	2,996,672	5,540,977	5,752,672
13 - 13.999						
12 - 12.999						
11 - 11.999						
10 - 10.999						
9 - 9.999						
Below 9.000						
TOTAL	32,215,501	7,428,662	8,086,394	7,069,137	6,614,506	6,999,057
Percent of Volume						
24 - 24.999						
23 - 23.999						
22 - 22.999						
21 - 21.999						
20 - 20.999						
19 - 19.999						
18 - 18.999						
17 - 17.999						
16 - 16.999	16.39	9.04	10.75	13.95	14.07	.95
15 - 15.999	3.16	1.88	35.72	43.76	2.05	17.00
14 - 14.999	80.54	89.08	53.53	42.29	83.88	82.05
13 - 13.999						
12 - 12.999						
11 - 11.999						
10 - 10.999						
9 - 9.999						
Below 9.000						
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00



Opinion and Order

[12,207]

RATE SCHEDULE, RATE CHANGE AND QUALITY STATEMENT

1. PRODUCERS NAME AND RATE SCHEDULE NO.	2. PURCHASER
3A. APPLICABLE SECTION 4(e) OR 7(c) DOCKET NO.(s)	3B. AREA RATE DOCKET NO. (IF ANY)

4. DATE(s) OF CONTRACT, AMENDMENT OR DISCOVERY 1/

	Contract	Amend.	New Res. Discovery	Date
A.	☐	☐	☐	Prior to* _____
B.	☐	☐	☐	On & After _____
C.	☐	☐	☐	_____

5. VOLUME @ 60° F AND _____ PSIA
A. _____ Mcf
(For latest available 12 months volume estimated if necessary)
B. Approx. % Gas Well Gas _____

6A. FIELD OR PLANT (NAME, STATE AND COUNTY, OR OFFSHORE AREA AND BLOCK NO.)	6B. INDICATE IF PRODUCTION FROM DISPUTED ZONE. ☐

7. GAS QUALITY, DELIVERY CONDITIONS AND REDUCTION FOR SUB-STANDARD GAS

		Content	Amount Reduction ¢/Mcf	FOR COMMISSION USE ONLY
A. 2/ IMPURITIES	a. Hydrogen Sulphide (gr./100 c.f.)			FPC GAS RATE SCHEDULE NO.
	b. Total Sulphur (gr./100 c.f.)			
	c. Carbon Dioxide (%)			SUPPLEMENT NUMBER
	d. Water (lbs./Mcf)			
	e. Other (Kind & Amount)			COMM. NO.
	f. Total Reduction for Impurities			DOCKET NO.
B. 2/ Delivery Pressure	a. Actual Delivery Pressure (Psig)			FILING DATE
	b. Pressure Available at Point of Delivery (Psig)			
	c. Reduction for Sub-Standard Pressure (¢/Mcf)			EFFECTIVE DATE _____

C. Delivery Point
a. Actual Point at which Gas is first Delivered to Purchaser:
☐ Wellhead; ☐ Central Point; ☐ Tailgate; ☐ Offshore Platform; ☐ Other
b. Point of Re-Delivery or Measurement for Payment: If Applicable.
☐ Wellhead; ☐ Central Point; ☐ Tailgate; ☐ Offshore Platform; ☐ Other
c. Reduction for Wellhead Delivery _____ ¢/Mcf

D. Total TOTAL REDUCTION FOR QUALITY AND DELIVERY DEFICIENCIES _____ ¢/Mcf

8. Heat Content 2/	A. Average Btu Content (Btu/c.f)			
	B. Btu Adjustment. Plus or (Minus). (¢/Mcf)			
9. APPLICABLE AREA RATES FOR SALE 3/	A. Base Area Rate(s) (¢/Mcf)			
	B. Base Area Rate (s) Less 7D Plus or Minus 8B (¢/Mcf)			
	C. Additional Amount for Offshore Gas Delivered Onshore (¢/Mcf)			
	D. Applicable Area Rate Here Estab. (Lower of 9B Plus 9C or 10A). (¢/Mcf)			
	E. Basis for Area Rate			
	F. Percent of Gas at Each Rate (If Unknown, Estimate.) 4/			
10. Rate Schedule Data	A. Contract Rate(s), ¢/Mcf)			
	B. Current Rate(s) As Filed, (¢/Mcf) 5/			
	C. Percent of Gas at Each Rate			

11. SIGNATURE OF SELLER, AGENT OR OPERATOR	TITLE	DATE
12. SIGNATURE OF PURCHASER	TITLE	DATE

(See Reverse Side For Footnotes)

FPC Form 193 (8-71)

FOOTNOTES:

1/ CHECK ONE OR MORE BOXES. INSERT APPROPRIATE DATE.

2/ NOT APPLICABLE TO CONTRACTS COVERED BY OPINION NO. 598.

3/ IF MORE THAN ONE BASE RATE IS APPLICABLE BY VIRTUE OF VARIATIONS IN DATES OF CONTRACTS, AMENDMENTS, AND/OR NEWLY DISCOVERED RESERVOIRS, OR DISPUTED OFFSHORE ZONE DELIVERIES; ENTER EACH BASE RATE DETERMINATION IN A SEPARATE VERTICAL COLUMN AND INDICATE ON LINE 9E THE BASIS FOR EACH RATE BY REFERENCE TO SECTION 4, OR SECTION 5B.
FOR EXAMPLE - IF MORE THAN ONE BASE AREA RATE IS APPLICABLE DUE TO VINTAGE (SEC. 4), ENTER AFTER ITEM 9E EITHER 4A, 4B, AND/OR 4C AS APPROPRIATE.

4/ THE TOTAL PERCENT FOR THIS LINE SHOULD EQUAL THE TOTAL ANNUAL VOLUME ITEM 5.

5/ THIS IS THE CURRENTLY EFFECTIVE RATE UNDER THE RATE SCHEDULE, AS FILED IN ACCORDANCE WITH SECTION 154.94 OR AS CERTIFICATED UNDER SECTION 157.23 OF THE COMMISSION'S REGULATIONS.

6/ REPORT AVERAGE BTU CONTENT OF SALES VOLUMES USED FOR BILLING.

Errata Notice

[12,210]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

ERRATA NOTICE

(January 5, 1972)

OPINION NO. 607

(Issued October 29, 1971)

Page 2, Footnote 4, change to read: 34 FPC 159, modified 34 FPC 1065 (1965), aff'd 390 U.S. 747 (1968).

Page 2, Footnote 5, change to read: 40 FPC 30 (1968), modified 41 FPC 301 (1969), aff'd 428 F.2d 407 (CA5, 1970), *cert. den.* 400 U.S. 950 (1970).

Page 6, Footnote a, change "contral" to "central".

Page 7, Footnote 8, line 4, change "Exhibit B" to "Appendix B".

Page 11, Paragraph 14, line 5, change "428 F.2d at 44" to "428 F.2d at 441".

Page 13, Paragraph 16, line 4, change "price" to "prices".

Page 14, Paragraph 17, line 7, change "(1971)" to "(1970)".

Page 34, Footnote 24, change "Texas Gulf Coast" to "Other Southwest".

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Errata Notice

Page 36, Line 3, change "§ 154.019" to "§ 154.109a".

Page 37, Line 19, change "Sept. 30, 1973" to "Sept. 30, 1974" and "October 1, 1973" to "October 1, 1974".

Page 39, Paragraph (3), line 2, change "standard" to "standards".

Page 40, Line 1, Change "(f)" to "(e)".

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Page 41, Paragraph (4), line 5: change to read: "in paragraph (c) (3) of Section 154.109a as added by ordering" line 9: change "154.109" to "154.109a".

KENNETH F. PLUMB
Secretary

[12,212]

UNITED STATES OF AMERICA

BEFORE THE
FEDERAL POWER COMMISSION

Docket No. AR67-1

IN THE MATTER OF:

AREA RATE PROCEEDING

(OTHER SOUTHWEST AREA)

SUPPLEMENTAL APPLICATION OF AMOCO PRODUCTION COMPANY FOR REHEARING

Amoco Production Company, Amoco, pursuant to Section 19a of the Natural Gas Act, 15 U.S.C. § 717r(a) and Section 1.34 of the Commission Rules, 18 C.F.R. §1.34, hereby files its supplement to the application for rehearing being filed by Shell Oil Company, *et al.*, with respect to Opinion No. 607 and accompanying Order issued October 29, 1971.

Without making findings as to impact of ceiling rates so as to test such assumption, the Commission assumes that the area ceiling rate levels prescribed in the Order accompanying Opinion No. 607 will constitute an ade-

quate and proper incentive for finding and developing the necessary increase in natural gas supplies in the Other Southwest Hearing Area and will make it economically feasible for independent producers to conduct the required gas well drilling programs. The institutional requirement of long term gas sales contracts and contract pricing schedules that has been imposed upon independent producers

limits the applicability of incentives the Commission seeks to implement by issuing Opinion No. 567. Where long term pricing schedules prohibit adequate revenue levels, neither the area ceiling rates prescribed in the Order accompanying Opinion No. 607 nor the area ceiling rates proposed in the application for rehearing of Shell Oil Company, *et al.*, will make it economically feasible to develop gas reserves in the Other Southwest Area to the extent required by the public interest.

In the "Initial Response of Amoco Production Company to Notice Instituting Proposed Rulemaking" filed in Docket No. R-425, Amoco showed that Commission Opinion No. 567 constitutes an incentive for development of reserves committed to old contracts in only the Southern Louisiana Area but has de minimus applicability in the remaining producing area of the Continental United States. Opinion No. 567 should be amended to provide that the price incentive provided therein applies to all newly drilled wells on previously committed acreage so that the incentive to fully develop previously committed acreage will be as great in the Other Southwest Area as it is in the Southern Louisiana Area.

Neither adequate area ceiling rates nor revision of Opinion No. 567 will affect development of gas res-

ervoirs that are trapped in long term contract pricing schedules in old contracts entered into under conditions that do not even remotely reflect present day conditions. Regardless of the level of area ceiling rates prescribed, potential gas reserves and additional deliverability that are governed by long term schedules of low prices in old contracts will not be developed because the necessary drilling is not economically feasible at such prices.

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Revenue at 1950 price levels will not support development of reserves where drilling must be paid for at current cost levels.

Long term pricing schedules that have the effect of prohibiting full development of gas reserves covered by such pricing schedules are contrary to the public interest. They deprive consumers of needed gas that would be made available at the just and reasonable area rate. In order to free such gas reserves for development and use to supply the energy needs of ultimate consumers, the Commission should promulgate a statement of policy stating that it will expeditiously grant permission to abandon acreage, formations and gas well locations where the purchaser under the present contract is unwilling to renegotiate the contract to permit collection of area rates prescribed by the Commission. Under such policy, purchasers would have the option of paying the area rate or releasing gas to be developed for other purchasers that are willing to pay the Commission determined area rate so as to make it economically feasible to drill the necessary wells.

WHEREFORE, Amoco Production Company respectfully requests that the Commission modify its Opinion

No. 567 as indicated above and issue a statement of policy that abandonment will be expeditiously granted in situations where the purchaser is unwilling to pay the just and reasonable area rate determined by the Commission in order to make it economically feasible to fully develop gas reserves committed to the contract.

Respectfully submitted,

WM. H. EMERSON
P.O. Box 591
Tulsa, Oklahoma 74102
Attorney for
Amoco Production Company

Dated at Tulsa, Oklahoma
November 24, 1971

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

IN THE MATTER OF
AREA RATE PROCEEDING, *et al.*,
(OTHER SOUTHWEST AREA)

APPLICATION FOR REHEARING OF INDICATED PRODUCER RESPONDENTS

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Tulsa, Oklahoma 74102

AMOCO PRODUCTION COMPANY
W. H. EMERSON
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Tulsa, Oklahoma 74102

ASHLAND OIL, INC.
TED HOLSHOUSER
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Oklahoma City, Oklahoma 73118

ATLANTIC RICHFIELD COMPANY
E. J. KREMER
P. O. Box 2819
Dallas, Texas 75221
CHARLES E. McGEE
McGEE & KETCHAM
1145 - 19th St. N.W.
Washington, D.C. 20036

THE CALIFORNIA COMPANY, A DIVISION OF CHEVRON OIL COMPANY
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1111 Tulane Avenue
New Orleans, Louisiana 70112
JUSTIN R. WOLF
1625 K Street, N.W.
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(List of Respondents Continued on Inside Front Cover)

[12,216]

Application for Rehearing of Shell Oil Co., et al.

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TEXACO INC.
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KIRK W. WEINERT
JOHN M. YOUNG
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Houston, Texas 77052

November 24, 1971
Houston,Texas

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TABLE OF AUTHORITIES

Cases

Associated Oil & Gas Co. v. *F.P.C.*, 280 F.2d 31 (5th Cir. 1960)

F.P.C. v. *Sunray DX Oil Co.*, 391 U.S. 9 (1968)

Mississippi River Fuel Corp. v. *F.P.C.*, 202 F.2d 899 (3d Cir. 1953)

Permian Basin Area Rate Cases, 390 U.S. 747 1968)

Sunray Mid-Continent Oil Corp. v. *F.P.C.*, 364 U.S. 137 (1960)

United Gas Pipe Line Co. v. *Mobile Gas Service Corp.*, 350 U.S. 332 (1956)

Application for Rehearing of Shell Oil Co., et al.

Administrative Decisions

Area Rate Proceeding (Hugoton-Anadarko Area), Docket Nos. AR64-1, *et al.*, Opinion No. 586, issued September 18, 1970, 44 FPC —— ——
Area Rate Proceeding (Other Southwest Area), Docket Nos. AR67-1, *et al.*, Initial Decision issued September 22, 1969, —— FPC —— ——
Area Rate Proceeding (Permian Basin Area), Docket Nos. AR61-1, *et al.*, Opinion No. 468, 34 FPC 159 (1965) —
Area Rate Proceeding (Permian Basin Area), Docket Nos. AR61-1, *et al.*, Opinion 468-A, 34 FPC 1068 (1965) —
Area Rate Proceeding (Southern Louisiana Area), Docket Nos. AR61-2, *et al.*, Opinion No. 546, 40 FPC 530 (1968) ——
Area Rate Proceeding (Southern Louisiana Area), Docket Nos. AR69-1, *et al.*, Opinion No. 598, 46 FPC —— (1971) ——

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Area Rate Proceeding (Southern Louisiana Area), Docket Nos. AR69-1, *et al.*, Opinion No. 598-A, 46 FPC —— (1971) ——
Area Rate Proceeding (Texas Gulf Coast Area), Docket Nos. AR64-2, *et al.*, Opinion No. 595, 45 FTC —— (1971) ——
Area Rate Proceeding (Texas Gulf Coast Area), Docket Nos. AR64-2, *et al.*, Opinion No. 595-A, 45 FPC—— (1971) ——
Hugoton-Anadarko Area Proceeding (Committed Acreage), Docket No. AR64-1 (*Severed Issued*); *Permian Basin Area Rate Proceeding*, AR61-1; *Southern Louisiana Area Rate Proceeding*, AR61-2, Opinion No. 567, 42 FPC 726 (1969) ——
Texaco Inc., et al., Opinion No. 464, 33 FPC 1228 (1965) —

Statutes

Natural Gas Act of June 21, 1938, c. 556, 52 Stat. 821, as amended, 15 U.S.C. § 717, *et seq.*

Section 4(e) ——
Section 19 ——

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Application for Rehearing of Shell Oil Co., et al.

Rules and Regulations

Federal Power Commission Rules of Practice and Procedure, 18 C.F.R. Chap. 1, § 1.34 _____
§ 2.56 _____
Regulations Under The Natural Gas Act, 18 C.F.R. Chap. 1 Section 157.40 _____

Miscellaneous

Future Gas Requirements of the United States, Vol. No. 4, October 1971 _____
Illustrative United States Gas Supply-Demand Balance, 1970-1990, F.P.C. Bureau of Natural Gas _____
Potential Supply of Natural Gas In The United States As Of December 31, 1970, Potential Gas Agency, Colorado School of Mines _____
Sales By Producers of Natural Gas To Interstate Pipeline Companies, 1969 U.S. Energy Outlook, Vol. 1, July, 1970, National Petroleum Council _____

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

IN THE MATTER OF
AREA RATE PROCEEDING, *et al.*,
(OTHER SOUTHWEST AREA)

APPLICATION FOR REHEARING OF INDICATED PRODUCER RESPONDENTS

I. INTRODUCTION

The indicated producer respondents[1] apply for rehearing of the Federal Power Commission's "Opinion and Order Determining Just and Reasonable Rates for Natural Gas Produced in the Other Southwest Area" issued October 29, 1971, and identified as Opinion No. 607. This Application is filed pursuant to Section 19 of the Natural Gas Act ("Act")[2] and Section 1.34 of the Commission's Rules of Practice and Procedure.

As grounds for rehearing, Respondents present the specifications of error contained herein, and state that in

[1] The respondents joining in this Application for Rehearing are identified on the cover hereof. This joint Application is filed to avoid duplicity of presentations; however, each respondent reserves the right to file separate or supplemental Applications for Rehearing.

[2] 15 U.S.C. § 717(a), *et seq.*

each instance the Commission (1) abused or exceeded its authority, or (2) made findings of fact or conclusions of law contrary to, or not supported by, substantial evidence. As in its Opinions in *Southern Louisiana II* and *Texas Gulf Coast*, the Comission recognized the need for provid-

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ing incentive prices to the gas producing industry (Op. 607, p. 11). The Commission also recognized the necessity of having the prices established be competitive with those offered by present and potential intrastate buyers in the area (p. 11). It recognized the importance of allowing the Other Southwest Area to realize its full potential as a gas producing area (p. 9). The Commission repeated its conclusions that cost calculations were inaccurate and subject to substantial variations, as it found in the *Southern Louisiana II and Texas Gulf Coast* decisions (p. 16). It recognized the need to take official notice of more recent data which has become available since the conclusion of the hearing (p. 7, fn. 8). The Commission also recognized the need for increases in flowing gas rates in order to provide the necessary capital for additional gas exploration (p. 12).

The undersigned respondents agree with and support all of these basic policy decisions by the Commission. In applying these policies to the facts in the Other Southwest Area however, the Commission has committed a number of errors, which we shall specifically enumerate.

In failing to further close the gap between the unrealistically low natural gas ceiling rates and the cost to the consumer of synthetic gas, liquefied natural gas, and other fuels, the Commission has perpetuated the economic distortion which has led to the crisis in gas supply which the Commission itself has recognized. As

we shall show, more recent data, if considered by the Commission, would require substantially higher ceiling rates.[3]

II. THE COMMISSION ERRED IN FAILING TO ESTABLISH RATES AT LEVELS ADEQUATE TO ELICIT NEEDED GAS SUPPLIES

By numerous decisions and actions, the Commission has recognized the existing gas shortage, and the need for potential supplies to be "fully utilized in this time of national need for all available

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gas" (Op. 607, p. 9). However, the rates established by the Commission in the Other Southwest Area are inconsistent with this objective. Thus, while the Commission has ostensibly disavowed the Examiner's conclusion (Init. Dec., p. 17) that no supply shortage exists, the end result of its consideration is the same. The effect of Opinion 607 will be to perpetuate the supply-demand imbalance acknowledged by the Commission to exist.

Certainly inadequate gas prices have contributed to the present gas shortage; in order to alleviate this shortage the Commission should establish prices that will encourage the exploration for, and development of, reserves in the Other Southwest Area. As we elsewhere demonstrate, existing rates fail to even cover the credible range of current gas costs. The Commission must recognize

[3] For example, according to the Commission Staff study on intrastate prices released on November 8, 1971, the weighted average contract price for intrastate sales in the Other Southwest Area jumped from 18.69 cents in the first half of 1970 to 25.21 cents in 1971.

that new supplies can only be obtained at increasingly higher cost.

A. The Commission Erred in Understating the Reserves Potential of the Other Southwest Area

According to the Potential Gas Agency, potential reserves [4] of the Other Southwest Area are as follews:

POTENTIAL RESERVES—TRILLIONS OF CUBIC FEET

	Probable	Possible	Speculative	Total
Area B—(Mississippi, Alabama and Florida)	3	15	53	71
Areas D & F (North Louisiana, Arkansas, East and Central Texas)[5]	10	25	58	93
Total	13	40	111	164[6]

Source: Release dated June 2, 1971, Potential Gas Agency, Colorado School of Mines.

It is evident that significant amounts of gas reserves remain to be discovered. The Commission must design gas prices in a credible

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range in order to elicit these more costly supplies, otherwise gas potential will remain undeveloped.

It is apparent that the Commission erred in considering only "probable reserves" in its analysis of potential gas supplies in the Other Southwest Area. The figure of

[4] As of December 31, 1970.

[5] Texas Railroad Districts 5, 6, 7B, and 9.

[6] This potential may be considered conservative as it excludes "Other Oklahoma."

15-18 trillion cubic feet utilized by the Commission (p. 11) is but 9 to 11 per cent of the total potential shown above, the finding and development of which is contingent upon prices substantially above those established by the Commission. We fail to understand how the Commission can recognize the developing gas shortage and the increasing need for activity to find marginal supplies, but at the same time suggest that "the prices established herein provide incentives."

The Commission errs further in indicating that the Other Southwest Area has less potential than the Texas Gulf Coast and Southern Louisiana. It is stated, "this area [Other Southwest] is unlike Texas Gulf Coast and Southern Louisiana, where there is the still largely untapped offshore potential" (Op. 607, p. 10).

In fact, the Potential Gas Agency indicates a potential of 164 trillion cubic feet for the Other Southwest (supra), compared with a potential of 145 trillion cubic feet in South Louisiana and 154 trillion cubic feet in the Texas Gulf Coast.[7] To the extent that the Commission's unduly low area ceiling rates were predicated on the assumption that the area contains a minimal potential, clearly such finding is erroneous and must be set aside on rehearing.

These vast potentials in the Other Southwest could help alleviate the shortages in consuming regions served by gas from this producing area. In 1970 the regional consumption of gas produced in the Other Southwest regions was as follows:[8]

---

[7] Release dated June 2, 1971, Potential Gas Agency, Colorado School of Mines. This estimate included 39 trillion cubic feet in the offshore of Mississippi, Alabama, and Florida, most of which is outside the Other Southwest Area.

[8] Exhibit No. 2, AR70-1.

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	Per Cent
New England	1.9
Appalachian	14.3
Southeast	6.6
Great Lakes	4.6
Northern Plains	0.8
Mid-Continent	27.7
Gulf Coast	44.1

B. The Commission Erred in Underestimating the Demand Requirements

The Future Requirements Committee forecast annual gas deficiencies from 1971 to 1975 in the regions referred to above. In 1975 these shortages are projected as follows:

GAS SHORTAGE FORECAST FOR CONSUMING REGIONS SERVED BY OTHER SOUTHWEST GAS [9]

	BCF	Per Cent of Demand
New England	18	5.4
Appalachian	741	14.2
Southeast	535	24.0
Great Lakes	1055	23.7
Northern Plains	112	9.5
Mid-Continent	225	11.4
Gulf Coast	610	7.2
Total	3296	

NOTE: Data reflect a Btu content of 1,000 Btu's per cubic feet.

Numerous other sources of recent vintage forecast even greater shortages of gas in the United States main-

[9] *Future Gas Requirements of the United States*, Vol. No. 4, October 1971, as prepared by the Future Requirements Committee.

land[10] in 1975 and 1980. For example, the FPC Bureau of Natural Gas forecasts national shortages amounting to 6.1 Tcf and 8.9 Tcf in 1975 and 1980,

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respectively.[11] It should be noted that this forecast was predicated on declining domestic production.

In a recent publication,[12] the National Petroleum Council forecast a greater national shortage, *i.e.*, 7.6 Tcf and 11.8 Tcf in 1975 and 1980, respectively. This projection assumed even faster declines in domestic production.

C. The Rates Adopted Are Inadequate to Stimulate Significant New Supplies

The Commission indicated its view that the rates prescribed in Opinion 607, ". . . should encourage new exploration and development in the 'Other Southwest Area' . . ." (p. 12). Upon careful analysis, it is evident that the rates established are wholly inadequate for the purpose.[13]

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[10] Contiguous 48 states.

[11] "Illustrative United States Gas Supply-Demand Balance, 1970-1990," prepared by the FPC Bureau of Natural Gas, and set out at Table 3 of the statement by Chairman Nassikas before the Subcommittee on Communications and Power, Committee on Interstate and Foreign Commerce, House of Representatives, September 21, 1971.

[12] *U. S. Energy Outlook*, Vol. 1, July 1971, National Petroleum Council.

[13] In utilizing the Examiner's level of E&D expenses in estimating flowing gas costs, the Commission has erred by using costing methods based on the Examiner's allegation that no supply shortage exists. These prices are understated by more than 2¢ per Mcf reflecting as they do the Examiner's erroneous rejection of direct assignment of E&D costs (Init. Dec. p. 87-88). In Opinion

After adjustment for inflation, the prices established for the Other Southwest Area by the Commission are no higher than histor-

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ical levels. The following table compares present base area rates with historical initial prices, adjusted for inflation.

Opinion 607 Base Area Rates

	Contracts on or After 10/1/68[14]	Contracts Before 10/1/68[14]	Initial Price[14]	Adjustment Factor[15]	Initial Price Adjusted
	(1)	(2)	(3)	(4)	(5)
Other Oklahoma	23.75	19.4	15.0	135	20.25
Texas District No. 9	24.0	19.7	14.5	135	19.58
Northern Arkansas	23.0	18.8	—		
Texas District No. 5	23.5	—	14.5	135	19.58
Texas District No. 6	23.5	19.1	15.0	135	20.25
North Louisiana	25.0	20.6	18.75	135	25.31
Southern Arkansas	22.5	18.25	—		
Onshore Mississippi	25.0	20.0	21.5	135	29.02
Northwest Alabama	25.0	20.0	—		
Offshore Mississippi	26.0	—	—		

598, the Commission accepted Staff's recommendation to use the direct assignment method (p. 61).

The comparative figures are as follows:

	Initial Decision[a] In AR67-1	Opinion[b] No. 598
E&D Expense	3.53	5.471
E&D Return (at 15 per cent)	.71	1.274
	4.24	6.745

[a] Initial Decision, p. 89; using modified Btu allocation procedure at 14.73 psia.

[b] P. 62; Exhibit No. 77 in AR69-1, at 14.73 psia.

[14] Opinion 607, p. 33A.

[15] Implicit Price Index 1960 = 100, from U.S. Department of Commerce, through first half 1971.

Two facts are apparent from this comparison. First the base area rates now established for pre-October 1, 1968 Contracts (Col. (2)) are in every instance but one, less than the decade-old initial prices merely adjusted for inflation (Col. (5)). There is no rational basis to believe that establishment of lower rates in constant dollars than existed while the gas supply crisis was germinating can now alleviate that crisis.

Secondly, while the base area rates for newer contracts (Col. (1)) are higher than the adjusted initial prices (Col. (5)) in most instances, the margin of increase is inadequate, considering the recognized need for greater capital formation (Op. 607, p. 12) and the experienced and expected rate of cost increase to which the independent producer is subject.

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Promulgation of field prices from 18¢-25¢ per Mcf contrasts starkly with the fact that gas distributors and pipelines seek to purchase synthetic gas at prices over $1.00/Mcf. It is anomalous for the Commission to expect a minimal increase of pennies in the field price to encourage new exploration and development while at the same time it is considering applications involving far more costly supplemental gas supplies. To illustrate, it has been estimated [16] that the prospective cost of supplemental base load supplies range as follows:

Natural gas from the Alaskan North Slope	75-100¢/Mcf
Imported LNG	75-100¢/Mcf
Synthetic Gas manufactured from Naphtha and LPG	110-140¢/Mcf
Synthetic Gas manufactured from Coal	75-125¢/Mcf

[16] Exhibit No. —— (RLS-1), Docket No. R-425, Schedule 25.

These supplemental supplies will cost more than twice the current city-gate price of supplies from the Other Southwest.

Stringent sulfur restrictions in large metropolitan areas throughout the United States, recently promulgated, dictate greater demand for natural gas. In the main, these regulations have evolved since the close of evidentiary hearings in Docket No. AR67-1. For example, fuels in Chicago are limited to a sulfur content ranging from 1 to 1.8 per cent by weight, depending on type of use. This has resulted in significantly higher prices for alternative low sulfur fuels (coal and fuel oil) in this area, substantially in excess of city-gate prices of Other Southwest supplies.

The Commission also has available to it evidence showing that gas prices, even considering the increases permitted by Opinion 607, will be substantially below the cost to the consumer of alternative fuels, such as electricity, fuel oil, and coal. The Exhibit sponsored by Witness Schantz filed as an attachment to the Comments of the major producers in the *Rocky Mountain Area Rate Proceeding*, Docket No. R-425, substantiate this fact in detail. As long as the substantial gap exists between natural gas and other fuels at the

consumer level, an artificial demand will continue to exist for natural gas, and the demand-supply gap will continue to widen.

D. The Moratorium Imposed is Not Consistent With the Commission's Findings on Supply and Demand

The five-year moratorium on price increases in the Other Southwest prescribed in Opinion 607 can only

serve to accelerate the existing inadequacy by foreclosing the possibility of further increases for an unreasonably lengthy period of time.

The five-year moratorium is particularly inconsistent with the public interest due to the extensive changes which have occurred in the gas industry since the end of evidentiary hearings in the Other Southwest. We list some of these significant developments as follows:

(1) Gas distributors and pipelines throughout most of the United States have instituted curtailments.

(2) Gas distributors and pipelines are currently contracting for supplemental gas supplies at more than twice the cost of domestic natural gas sold by pipelines to distributors.

(3) Stringent sulfur restrictions evolving in large metropolitan areas throughout the United States dictate greater demand for natural gas.

(4) The cost of alternative low sulfur fuels—coal and residual fuel oil—has increased substantially.

(5) New reserves additions have amounted to only half of net production in the United States Mainland in the last three years; thus, the RP ratio has declined to a historic low of 11.9-to-1.

The risks to consumers created by the incipient gas shortage are immeasurably large, while the cost of attempted relief is small by comparison. Natural gas is substantially underpriced in comparison with costs of alternative fuels throughout the United States. Thus major shifts in fuel consumption patterns are unlikely even with gas prices substantially above those established in Opinion 607.

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The rapidity with which the gas supply crisis has de-

veloped should be a sufficient indication that no moratorium should be imposed. It is not possible at this time to determine what prices may be required during the next five years to meet the public interest in an adequate gas supply. The imposition of such a moratorium for post-10/1/68 sales might simply mean that the bulk of new supplies would be acquired by the intrastate buyers.

On rehearing, the Commission should reconsider the length of the moratorium period, being mindful of the rapidity with which full awareness of the current gas shortage has descended upon the gas industry.

E. If Refunds Are Required, A Refund Credit Procedure Should Be Adopted As An Additional Incentive

In its *Southern Louisiana* decision the Commission provided an optional method of refund credit by the commitment of gas to interstate commerce stating:

> "We therefore find a refund credit, of one cent for each Mcf of new gas reserves committed to jurisdictional sale from the area to be in the public interest. We find such an incentive will be of net benefit to the consumer, by obtaining additional gas supplies." (Op. 598, p. 69)

In Opinion 607, the Commission has ordered that refunds be made without credit provision, stating:

> "The refunds here ordered are of such small amount that a refund credit would not provide an incentive to any materially increased exploration and development program; in this respect Other Southwest is different from Southern Louisiana and Texas Gulf Coast." (Op. 607, p. 32)[17]

[17] We note that Opinion 607, at p. 45, ordering Paragraph (J), apparently contemplates the use of a refund credit procedure, despite the text of the Opinion at p. 32.

The order fails to state the number of dollars viewed by the Commission as a "small amount." However, it is Respondents' pre-

liminary estimate that the total refund obligation may exceed $5,000,000.

To require cast refunds of this magnitude would operate as a disincentive to eliciting new gas supplies to the interstate market. By requiring cash refunds, the dollars available to finance new exploration activities are reduced, *pro tanto*. Certainly there is a *de minimus* point where no refund credit provision is needed but that point must be less than the several million dollars involved here. There is no apparent reason why individual producers should not be given the option here, as in Southern Louisiana and Texas Gulf Coast, to discharge refunds in cash or by new reserves commitments. It is at least arguable that consumers will benefit more from the commitment of new reserves than from the minute amounts of cash refunds to be received by individual consumers.

III. UTILIZING THE COST DATA IN THE RECORD AND DATA SUBSEQUENTLY AVAILABLE, THE COMMISSION'S RATE LEVELS ARE INADEQUATE

A. Introduction

The Commission fixed ceiling prices based on a melange of cost estimates—its own estimate of the current cost of new non-associated gas, the Examiner's estimate of "current" cost, and the Examiner's findings concerning the area historic cost of flowing gas as of 1962. Differential rates were established for gas in the several

sub-areas of the Other Southwest, for gas of different vintages and for gas delivered in different time periods. However, there is no indication that the Commission determined the applicable ceiling prices for the various sub-areas, vintages and delivery periods in light of any consistent theory with respect to regulatory method or rate design.

While the Commission state that it relied on its prior determinations concerning the meaning and imprecision of the new-gas cost estimates (Opinions 595 and 598) and the capital requirements of the industry (Opinion 598), the Commission erred in

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failing to give appropriate consideration to its prior analyses of the regulatory problem. The most significant elements of Opinion 598 were (1) the conclusions concerning the meaning and nature of the cost estimates, (2) the recognition of the role of flowing-gas prices in providing the capital needed for an increased exploration program, and (3) the conclusion that it was necessary to evaluate the total rate design in terms of its probable effectiveness in meeting the Commission's supply objectives.

B. The "Costs" Used By the Commission Are Understated

The ceiling prices adopted by the Commission are largely based on estimated "costs" of one type or another, although there was some limited consideration of other factors. To the extent that the ceiling prices are based on costs, there is no indication that the Commission gave measured consideration to the meaning of the cost estimates or to their inherent imprecision and limitations.

The Commission used three "cost" reference points in deriving its price ceilings: (1) the Commission's own estimate (in Opinion 595) of the range of current costs of new non-associated gas (22 to 26 cents per Mcf); (2) the Examiner's recommended ceiling prices for gas sold under contracts dated 1/1/61 or later, based on the Examiner's conclusion concerning the then-current nationwide cost of new non-associated gas; and (3) the Examiner's flowing gas costs as of 1962 for each subarea. The cost estimates were employed as follows:

(1) The Commission's current cost estimates of 22-26 cents per Mcf is used as the basis for establishing ceiling prices for third-vintage gas, *i.e.*, gas sold under contracts dated on or after 10/1/68.

(2) The Examiner's cost-based ceiling prices for gas sold under contracts dated 1/1/61 or later are used for deliveries of second-vintage gas for the period prior to 1/1/65. The ceilings thus derived are increased ½-cent as of 1/1/65 and an additional ½-cent as of 10/1/68. For deliveries on and after 10/1/68, the same ceiling is applied for deliveries

under first-vintage (pre-1/1/61) contracts as for second-vintage 1/1/61-9/30/68) gas.

(3) The Examiner's flowing-gas costs for each pricing area within the other Southwest are used as the primary basis for the establishment of ceiling prices for deliveries of first-vintage gas in the period prior to 1/1/65. The ceiling prices for deliveries of first-vintage gas in the period 1/1/65-9/30/68 are apparently selected to fall approximately mid-way between the ceilings for deliveries in the prior and the subsequent period.

Each of the cost estimates on which the Commission relies is understated, and the minor escalations included to allow for cost increases after the "base" dates are inadequate. We discuss these cost estimates below.

1. The Commission's Current Cost Estimate of 22-26 Cents Is Understated

We demonstrated in depth in the Application For Rehearing filed in the *Texas Gulf Coast Area Rate Proceeding* [18] that the estimate of the "credible range" of new-gas costs is significantly understated in terms of the past experience and even more seriously understated as an estimate of the prospective cost to be incurred in finding the needed gas supplies. If adjustments are made only to certain egregious errors in specific cost components, the adjusted costs become *27.52* to *34.38* cents per Mcf, inclusive of production taxes at the Texas rate of 7.5 percent.

Opinion 607 mentions the additional current cost evidence presented in *Southern Louisiana II* which was not available in *Texas Gulf Coast*, but there is no indication that the Commission adequately evaluated that evidence. That evidence showed that the current cost of new nonassociated gas as of 1969 was in the range of 31.3 to 39.5 cents per Mcf at a 15 percent return and 32.2 to 40.9

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cents per Mcf at a 16 percent return. The figures are at 14.65 psia and include Texas production taxes at 7.5 percent.[19]

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[18] For the convenience of the Commission, this discussion is reproduced and attached hereto as Appendix A.

[19] Docket No. AR69-1, Exh. No. 63 (Sherwin); computations at a 15 percent return and Texas production taxes are added.

The Commission emphasized in Opinion 595 that the relevant cost is the cost which must be incurred to elicit new supplies, including a return commensurate with that available from alternative investment opportunties of equivalent risk. As a starting point in estimating this cost, the so-called "current" cost estimates should in fact be made current. In view of the sharp inflationary trends in the economy in recent years, the retrospective estimates are quickly outdated. Thus, the drilling-cost estimates used in *Southern Louisiana II* were as of the year 1969, but as of 1971 the per-foot drilling costs are at least ten percent higher. Allowing for this rise in drilling cost per foot, the current cost of new non-associated gas in the range of 32.9 to 41.6 cents per Mcf at a 15 percent return or 34.0 to 43.0 cents at a 16 percent return; the figures are inclusive of Texas production taxes at 7.5 percent.[20]

The Commission in effect recognized an appropriate economic principle in Opinion 595, when it stated:

> "We believe the testimony of the producer witnesses is credible and essentially unchallenged, to the effect that when the level of drilling is up, the incremental productivity is lower because the companies tend to drill the riskier projects. We think, therefore, that we are justified in using relatively lower productivity rates in our calculations, in our generalized review of costing models. Even more specifically, we believe the interest of meeting rising demand for natural gas dictates that we provide incentives to explore, even where the expectations are sharply lower than heretofore, simply because domestic gas is likely to be cheaper than the imported or synthetic alternatives." (p. 32)

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[20] This estimate is detailed in Appendix B attached hereto.

Inasmuch as this principle cannot be determined by exclusive reference to data for past periods, the Commission on rehearing should consider alternative and supplementary approaches to estimating the incentive price, *e.g.*, prices of alternative gaseous fuels and other

energy sources, the prospective changes in cost and price levels, and the past trend in costs.

2. The Examiner's New-Gas Cost Is Erroneous

The ceiling prices established for gas sales under contracts dated prior to 10/1/68 are based on the Examiner's determination that the "current" nationwide cost of new non-associated gas was 16.22 cents per Mcf, including production taxes at 7 percent. The Commission added escalations of 0.5 cents as of 1/1/65 and an additional 0.5 cents as of 10/1/68. Thus, the Commission's ceiling prices for the period beginning 10/1/68 are apparently based on an estimated "cost" of 17.22 cents per Mcf.

Opinion 607 makes scant comment concerning the Examiner's current cost estimate of 16.22 cents per Mcf. The Commission noted only:

> "Substantial changes have occurred since the initial decision computed the new gas-well gas cost of 16.22 cents per Mcf. That decision was based on 1963 Census data for drilling costs per foot and dry hole costs per foot. The 1967 Census data indicates a substantial increase in these costs. The Examiner found that a 10.5 percent rate of return was appropriate, whereas in Opinion Nos. 595 and 598, we indicated that a rate of return of approximately

15 percent was reasonable." (Opinion 607, p. 13, footnote 15)

Assuming that the Commission intended to fix the ceiling for per-10/1/68 sales prospectively on the basis of the nationwide cost of new gas for the period *1961-1968*, the appropriate cost level for use in the computations is far higher than the 17.22 cents which was used by the Commission. Such cost level is, at a minimum, within the 22-26 cent cost range determined by the Commission in Opinion 595.

In Opinion 595, the Commission reviewed the findings of the Examiner in AR54-2 that the new-gas cost was 16.42 cents per Mcf, a figure almost identical with the new-gas cost of 16.22 cents determined by the Examiner in the instant proceeding. The Commission

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there discussed at length the imprecision of the cost estimates and reviewed in detail the alternative estimating procedures available for each of the cost components. It then determined a "variable cost range" for each of the components and, on the basis of these determinations, concluded that the credible range of current costs was from 22 to 26 cents per Mcf.

It is apparent from the detailed discussion of the cost estimates in Opinion 595 that the primary source of difference between the Examiner's findings and the Commission's conclusion was *not* the fact that the Commission's data were for a later period but rather that the Commission considered a wider range of alternative approaches to the process of cost estimation. Thus the Commission's current cost estimate of 22-26 cents incorporates data for the period 1961-1968 or for portions

of that period and makes but little use of data for the year 1969.[21] The appropriate cost level for pricing deliveries of pre-10/1/68 gas (for the period beginning 10/1/68) is thus no less than the range of 22-26 cents.

If the prospective prices for pre-10/1/68 gas were fixed by reference to the nationwide cost of new gas during the period 1961-1968, the applicable prices for deliveries prior to 10/1/68 might, following the Commission's procedure, be somewhat lower.

Alternatively, if the prospective (post-10/1/68) price is established by trending from some earlier base, following the Opinion 607 procedure, both the base and the escalations used by the Commission should be increased. The Commission in effect treated the Examiner's "current" cost estimate of 16.22 cents per Mcf as if it were applicable as of the year 1963.[22] The current cost estimate of 16.22 cents per

Mcf determined by the Examiner is subject to all of the uncertainties and infirmities which the Commission analyzed in detail in Opinion 595. Moreover, the cost as determined by the Examiner was clearly at the low end

[21] The upper limit of the range uses drilling costs as of 1969 and productivity averaged over 1947-1969. Additionally, production operating expenses are as of 1969 but the current level is of course applicable for all sales. Net liquid credit is derived by reference to data for 1965-1969, but the use of the more recent data for this component reduces the estimate of cost of gas.

[22] Although the Commission does not spell out its reasoning, this conclusion seems warranted because the Commission used the Examiner's ceilings for deliveries made prior to 1/1/65 under contracts dated 1/1/61 or later and because the Commission specifically refers to the Examiner's use of drilling costs for the year 1963.

of the range of estimates presented by the parties.[23] Under the circumstances, the "base" cost estimate should initially be expressed in the form of a range and it is difficult to understand the rationale by which the Commission adopted the Examiner's pin-point cost determination. To illustrate, if the Examiner's cost estimate were revised only to incorporate the 15 percent return which the Commission determined to be reasonable in Opinion 595, the adjusted cost estimate would be 19.10 cents per Mcf.

A further question concerns the appropriate escalations as of 1/1/65 and as of 10/1/68. The Commission added to the Examiner's cost-based prices escalations of ½-cent as of 1/1/65 and an additional ½-cent as of 10/1/68. Such escalations are entirely inadequate for the intended purpose. The escalations in applicable ceiling prices should reflect three types of cost increases: (1) the increase in cost resulting from the changing "mix" of deliveries as the more-recent, higher-cost vintages go onstream, (2) the increases in operating costs for all vintages over time, and (3) the increases in cost of replacing current production with new reserves. As pointed out in Opinion 598 (p. 60), traditional flowing gas cost methods provide at best only for replacement "at historic cost levels, of gas produced in the current year which does not provide any support for the presently needed exploratory effort to meet future demands." Cost increases of this type are illustrated in Appenlix D. It is evident, given the sharp inflationary trends of the last several years, that the escalations provided by the Commission are inadequate.

[23] The estimates presented by the parties ranged from 16.5 cents per Mcf (Staff) to 26.2 cents per Mcf (Respondents). [See Joint Brief on Exceptions of Humble Oil & Refining Company, *et al.*, page 170.]

3. The Examiner's "Flowing" Gas Cost Is In Error

The third cost reference point used by the Commission was the Examiner's "flowing" gas cost for the year 1962. The Examiner's cost determinations were made for each of three pricing areas in the Other Southwest. Although the Commission departed slightly from the Ex-

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aminer's cost-based ceiling rates for certain areas (Texas District 6, Northern Louisiana, and Mississippi), it failed to give adequate consideration to the range of uncertainties inherent in the flowing-gas cost estimates.

In Opinion 595, the Commission stated candidly:

> "We recognize that we have not given the matter of the elements of flowing gas costs the kind of analytical review we have bestowed on new gas costing." (p. 40)

and

> "One factor is very clear, and that is that here more than in the new gas costing methodology, even, the problem is in allocation of joint costs—and that is indeed an economic thicket. It is compounded by the fact that substantial variations exist in the percentage of joint costs from area to area, whereas for new gas, we have used national data." (p. 41)

In light of the Commission's acknowledgement that the uncertainities with respect to the flowing-gas cost estimates are even greater than with respect to the new-gas costs, if the flowing-gas costs are used for any rate design purpose, the Commission should give greater consideration to the *range* of historical costs as estimated by the parties. This cost range, for the Other Southwest as a whole, was from 12.1 cents to 21.7 cents per Mcf.

The Commission concluded that the range of uncertainty with respect to the new-gas cost was approximately 20 percent, *i.e.*, that the costs were in the range of 22-26 cents per Mcf. The uncertainties with respect to the flowing-gas costs are even greater, and the costs as determined by the Examiner were obviously at the bottom of the range. Assuming that the margin of uncertainty with respect to the "flowing" gas costs is 30 percent (and the indications are that the margin is considerably greater), the appropriate base rates for first vintage gas clearly are no lower than the rates established by the Commission for gas sales under contracts dated 1/1/61-9/30/68.[24]

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One other factor is extremely relevant here. The "flowing" gas costs are used (albeit with certain adjustments and escalations) as a basis for requiring refunds. In Opinion 595, the Commission, in explaining why it did not attempt to find a new starting point (other than the flowing gas costs) with respect to pre-1961 gas stated:

> "In part, our reasons relate to the fact that on policy grounds the amelioration of hardship arising out of any inadequacy in the price has to be handled on the refund issue, as to which we determine (hereafter) that additional incentives for further exploration and development can be provided in the public interest." (p. 41)

Thus, the Commission justified its use of flowing gas costs in *Texas Gulf Coast* on the grounds that it was

[24] The ceiling prices adopted by the Commission for second-vintage gas deliveries in the period to 1/1/65 exceed the Examiner's cost-based ceilings for first-vintage gas by 4.7 to 28.4 percent for the various sub-areas.

making provision for the discharge of refund obligations through the commitment of new reserves to interstate commerce. In the instant case, the Commission has made no such provision; instead, Opinion 607 orders refunds on the basis of a flowing gas cost which is admittedly imprecise and uncertain. On rehearing, the Commission should abandon any use of the 1962 sub-area flowing gas costs in fixing just and reasonable ceiling prices.

IV. THE COMMISSION ERRED IN ADOPTING ITS COMPLEX RATE DESIGN

A. Introduction

The Commission's rate design is a "crazy quilt" of sub-areas, gas vintages (*i.e.*, contract dates) and delivery periods. In all, Opinion 607 specified *73* separate prices for gas deliveries from the Other Southwest Area for the period prior to July 1, 1976. There is no indication that the Commission determined the applicable ceiling prices for the various vintages and delivery periods in light of any consistent theory with respect to rate design.

There is no reason why the rate design for the Other Southwest Area need be so complex. The range of probable error in cost and price levels is greater than the price differentials established among

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vintages, sub-areas, and delivery periods. The Commission's determination of a large number of separate "base area rates" imparts an aura of precision to the rate-making process which simply does not exist. It would be far more realistic for the Commission to acknowledge

that the rates can be established only within a zone of reasonableness and to simplify the entire rate design package.

B. The "Vintaging" of Gas Sales Is Erroneous

The Commission distinguished, for prospective pricing, between sales under contracts dated prior to and after 10/1/68. The two-vintage system and the 10/1/68 cut-off date conform with the procedure followed in Opinion 598. Respondents concur in the use of this procedure, assuming *arguendo* that the Commission adheres to some vintaging scheme.[25]

For past periods, *i.e.*, for refund purposes, Opinion 607 distinguishes three vintages—sales under contracts dated prior to 1/1/61; sales under contracts dated from 1/1/61 through 9/30/68; and sales under contracts dated 10/1/68 or later. Refund calculations should be based on

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[25] The ill effects of vintaging were discussed by Commissioner Carver in recent remarks before the Institute of Public Utilities on November 5, 1971, at the University of Michigan:

"Our objective should be to stimulate production by all elements and at all stages of the natural gas industrial process. To date, the price incentive element has been concentrated almost exclusively on exploration and development of new sources of supply. In comparative terms, at least, we have tendered a premium for the commitment of 'new gas' to the national market, while holding to rigid cost criteria for older reserves. This concept of 'vintaging' represents one of the contributions of your profession to our regulatory technique—and one whose attractiveness has now acquired tarnish.

"Whatever justification there may have been for such a policy in periods of rising reserves, it will most certainly have a negative effect as some of our most prolific gas fields begin to decline in productivity. A wellhead price structure that does not recognize marginality of increasing recovery costs can only promote premature abandonment. We can't afford to have all our eggs in the E&D basket as 'old gas' begins to make up a larger and larger segment of the known supply."

the same rates established for prospective application and not depend on a multiple vintaging concept for past periods.

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On rehearing, the Commission should move in the direction of establishing a single-price system for all gas sales or, in any event should reduce the differential between the applicable ceiling prices for "new" and "flowing" gas. To compound the vintaging process by distinguishing three rather than two types of contracts would serve no regulatory purpose.

C. The Relationship To Other Areas

The Commission apparently concluded that the price levels for the Other Southwest should be set at a lower level than for Southern Louisiana in light of historical pricing patterns (although it recognized that the guideline and in-line prices for Mississippi were higher than for Southern Louisiana). The Other Southwest price levels for new (post-10/1/68) sales are also lower than for the Texas Gulf Coast, for the most part. In Mississippi and Northern Louisiana, the new-gas ceilings for gathered gas are only marginally higher than for Texas Gulf Coast, although the ungathered new-gas ceilings are lower.

Although Respondents concur in the general principle that the ceiling prices for the various parts of the market should bear a reasonable relationship to each other, that principle should not serve as a justification for establishing ceiling prices below the levels required to meet the objective of eliciting the needed supplies. In the present situation, where there is general shortage of supply, the historical price relationships are not neces-

sarily relevant, and the factors which shaped those relationships in the past are not necessarily significant for the future. In the future, gas supplies will be of great value to consumers wherever they may be found, and the price ceilings for each area should be placed at a level which will elicit increased realization of that area's potential.

D. Intrastate Prices

Opinion 607 presents some limited information on intrastate prices through 1969, based on the Form 2 reports of interstate pipeline companies to the Federal Power Commission. The information

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available to the Commission was inadequate and outdated and the Commission consequently accord this information little weight in its determination.

Since the date of the Commission Opinion, current information has become available which shows the sharp rise in price levels which has occurred in the intrastate market (Docket No. R-389A, Report of the Investigating Officer, dated November 8, 1971, and similar prior report dated September 9, 1970). Comparative intrastate prices as reported for 1969, the first half of 1970, and the period since July 1, 1970 are as follows:

	1969			First Half 1970			7/1/70 And Later		
		Current Price a/			Current Price a/			Current Price a/	
Area	Annual Volume (bcf)	Wtd. Avg. (¢/Mcf)	Range (¢/Mcf)	Annual Volume (bcf)	Wtd. Avg. (¢/Mcf)	Range (¢/Mcf)	Annual Volume (bcf)	Wtd. Avg. (¢/Mcf)	Range (¢/Mcf)
Permian Basin	146	14.57	8.26-23.99	103	21.47	15.40-23.67	137	23.80	8.96-38.50
South Louisiana	10	20.38	19.50-23.68	72	22.98	20.50-30.00	25	26.22	20.25-39.56
Texas Gulf Coast	148	19.39	12.05-22.13	38	18.39	10.50-24.38	75	22.19	11.00-30.11
Ruston-Anadarko	6	17.32	15.00-19.33	15	21.55	18.00-24.04	45	22.65	9.25-35.36
Other Southwest	7	17.85	12.27-21.45	12	18.69	14.00-21.53	52	25.21	4.40-28.92
Rocky Mountain	0.7	11.57	9.75-12.00	8	18.05	6.83-19.02	20	17.32	6.00-25.00
California	9	31.36	25.00-35.25	1	30.43	25.00-31.00	11	34.09	27.00-37.00
Michigan	1	36.00	35.70-43.72	4	36.00	36.00	19	40.87	36.00-48.30

a/ Inclusive of tax reimbursement, additive and deductive adjustments for gathering and Btu. The prices for the contracts dated in 1969 and the first half of 1970 are as of August 1970; the prices for subsequent sales are as of September 1971.

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For the several parts of the Other Southwest, the intrastate prices and volumes have been as follows:

Area	1969 Annual Volume (Bcf)	1969 Current Price a/ Wtd. Avg. (¢/Mcf)	1969 Current Price a/ Range (¢/Mcf)	First Half 1970 Annual Volume (Bcf)	First Half 1970 Current Price a/ Wtd. Avg. (¢/Mcf)	First Half 1970 Current Price a/ Range (¢/Mcf)	7/1/70 And Later Annual Volume (Bcf)	7/1/70 And Later Current Price a/ Wtd. Avg. (¢/Mcf)	7/1/70 And Later Current Price a/ Range (¢/Mcf)
Arkansas	0.2	16.00	16.00	0.2	18.75	18.75	—	—	—
North Louisiana	2.7	21.45	21.45	—	—	—	0.3	20.58	19.50-21.45
Mississippi	—	—	—	1.0	20.96	20.96	—	—	—
Oklahoma	0.5	16.06	15.00-18.27	1.6	15.86	14.00-16.00	37.8	27.13	11.17-28.92
Texas District 5	1.9	13.91	12.27-17.64	1.0	18.50	18.50	9.9	21.80	18.00-27.45
Texas District 6	1.6	17.14	16.08-17.64	7.1	18.67	17.50-19.00	4.0	15.72	4.40-18.38
Texas District 9	—	—	—	0.9	21.53	21.53	—	—	—

a/ Inclusive of tax reimbursement, additive and deductive adjustments for gathering and Btu. The prices for the contracts dated in 1969 and the first half of 1970 are as of August 1970; the prices for subsequent sales are as of September 1971.

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It is apparent that prices in the intrastate market have moved up sharply in all the parts of the Other Southwest where there were significant volumes. For Oklahoma, the weighted average price increased from 15.86 cents in January-June 1970 to 27.13 cents for the more recent sales and the highest price rose to 28.92 cents. For Texas District No. 5, the price average rose from 13.91 cents in 1969 to 18.50 cents in the first half of 1970, and to 21.80 cents after 7/1/70; the highest price was 27.45 cents per Mcf.

On rehearing, the Commission should takes the intrastate price levels into account in fixing revised area rates, recognizing that prices at the upper end of the range will be required to compete for substantial reserves. Given the size of the intrastate market in the Other Southwest and the general scarcity of gas supplies, the bulk of any new findings would inevitably move intrastate if the Opinion 607 rates are allowed to stand.

E. The Relation Between the Ceilings and Average Revenues

The Opinion 607 rate design takes no account of the dispersion of existing prices in the Other Southwest and fails to recognize that the revenues which will be realized

at the proposed ceiling prices for pre-10/1/68 sales will be substantially lower than the ceilings.

While no estimate is available of prospective revenues under the Commission's order, it seems apparent that there would be revenue reductions for Mississippi and for Northern Louisiana.[26] For Mississippi, Respondents estimate that revenue reductions would be applicable to 46 percent of the total volume; for Louisiana, price reductions would be required for 16 percent of the volume. These estimated reductions in revenue, stated on an annual basis, are $1.0 million for Mississippi and $0.8 million for Northern

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Louisiana.[27] Thus, the Mississippi revenues would be reduced prospectively by 4.0 percent (from 18.9 to 17.9 cents per Mcf), and the Northern Louisiana revenues by 2.3 percent (from 16.4 to 16.0 cents per Mcf).

For Mississippi, there has been a steady attrition of producers' unit revenues throughout the 'sixties as a result of prior Commission actions. The average revenues for jurisdictional sales have been as follows:[28]

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[26] No information is available concerning the extent of any offsetting increase in revenues in the other parts of the Other Southwest, and Respondents are unable to determine whether the total effect of the Commission's order would be to increase or reduce revenues prospectively.

[27] The computation covers sales by producers with total jurisdictional sales over 10 million Mcf, and is based on the detailed information shown in the FPC publication, *Sales by Producers of Natural Gas to Interstate Pipeline Companies, 1969*, Table 4.

[28] 1961-1963: Exhibit No. 60 (Engel); 1964-1969: Opinion 607, Appendix C adjusted to exclude one Northern Louisiana sale. The data shown in Appendix C of Opinion 607 apparently include in the Mississippi figures one large sale which covers production from both Adams County, Mississippi, and Tensas Parish, Louisiana. In the computations herein, the Louisiana portion of the production is shown with Northern Louisiana.

	Cents Per Mcf
1961	21.21
1962	21.09
1963	20.27
1964	19.51
1965	18.78
1966	18.92
1967	19.21
1968	18.93
1969	18.89

For the Commission to reduce these revenues further, *i.e.*, to 17.9 cents per Mcf, would in effect mean that the recent decline in exploration would simply be accelerated.

The existing average revenue levels are clearly not excessive, and revenue reductions should not be required unless the rates in question are demonstrably excessive. The highest price as of 1969 for any sale in the Other Southwest was 24 cents per Mcf (15.025

psia). The guideline price established for Mississippi, over a decade ago, was 21.5 cents per Mcf. This minimal increase in price in this period of rapid inflation is clearly not excessive or unreasonable.

F. The Commission Should Re-Examine Its Determinations *De Novo*

Respondents believe that on rehearing rates should be determined for pre- and post-10/1/68 sales which will

permit the Other Southwest to make a reasonable contribution to national supply requirements. Rate recommendations by all parties at the close of the hearing and at oral arguments failed to anticipate the magnitude of the supply crisis.

Respondents urge the Commission on rehearing to adopt the following ceiling prices for the entire Other Southwest Area: [29]

	Contracts Dated Prior to 10/1/68	Contracts Dated 10/1/68 Or Later
Gathered gas	27.0	35.0

Note: Cents per Mcf at 14.65 psia.

The differentials for ungathered gas set forth in Opinion 607 are supported in the record and are appropriate for use with the recommended rates.

The experienced cost of new non-associated gas in recent years was in the range of 27.5 to 39.5 cents per Mcf, including a 15 percent return and including production taxes at 7.5 percent.[30] At a 16 percent return, the upper range of cost estimates is 40.9 cents. At a more current date (*i.e.*, mid-1971), the cost range is from 34.4

[29] If the Commission determines that the existing record as updated herein cannot be used as a basis for adopting Respondents' rate recommendations, then it is urged that the record be reopened.

[30] The 27.5 cents is the lower end of the variable cost range, obtained using Opinion 595 methodology as adjusted in Appendix A herewith; the 39.5 cents is from AR69-1, Exh. 63 (Sherwin), with adjustment of the rate of return to 15 percent and production taxes to the 7.5 percent level.

[12,246]

to at least 41.6 cents per Mcf.[31] Other factors are relevant here. The cost of finding and developing gas supplies has increased sharply in recent years. Drilling costs for gas wells and dry holes continue to rise, both because of the general price inflation and the shift to drilling in deeper formations and in less accessible locations such as the offshore area. It must be anticipated that costs will continue to rise, although it may be hoped that the rate of increase will be moderated by the Administration's program to control inflation.

Consideration should be given to additional information relevant to the estimate of the appropriate new-gas cost (or price). Supplemental supplies of natural gas or synthetic gas will cost an estimated 75-140¢ per Mcf, more than twice the current city-gate price of supplies from the Other Southwest (*supra*, p. 8). The prices which prevailed in the total Southwest market during 1958-1960, at a time when the market was functional, should be considered, and these prices trended to take account of the estimated change in cost and price levels thereafter. The 1958-1960 prices, as adjusted for cost changes, are relevant because these prices elicited a satisfactory level of exploration and delevopment in light of then current demand. Moreover, although more than a decade has passed, they are the best available indication of the verdict of the marketplace at a time when the market was functional. During the 1958-1960 period, the upper range of contract prices varied between 20

[31] The 34.4 cents is the upper end of the variable cost range, obtained using Opinion 595 methodology as adjusted in Appendix A herewith. The 41.6 cents is from Docket No. R-425, Exh. No. —— (CSG-1) of Celia Star Gody, Sch. 3, with production taxes added (Appendix B).

cents and 23.5 cents per Mcf in the several parts of the Southwest market. The indicated cost and price increases after 1959 were 38 percent for the consumer price index and for the implicit price deflator, 55 percent for composite construction costs and for average hourly earnings of petroleum workers, and 58 percent for gas-well drilling costs.[32] Trending the 1958-1960 price range of 20.0-23.5 cents by these indices, the comparable price levels derived as of 1971 range from 27.8 to 37.1 cents per Mcf.

[12,247]

For pre-10/1/68 sales, the recommended price ceiling is based, as a starting point, on the reasonable range of estimates of the cost of finding and devolping new non-associated gas supplies during 1961-1968. Appendix C shows the estimated nationwide cost of non-associated gas, based on evidence submitted in Docket No. AR69-1, prepared using identical estimating techniques year by year for 1961-1968.[33] The average non-associated gas cost for 1961-1968, using a 15 percent return and including production taxes at 7.5 percent is 27.14 cents per Mcf. At a 16 percent return, the trended 1961-1968 cost average would be 28.06 cents per Mcf.

The 27.0-cent price level for pre-10/1/68 sales provides a rational estimate of the price level which will generate increased cash flow to make available the needed capital. The use of the estimated 1961-1968 cost level as a basis for determining the funds required is reasonable. In constrast, the Opinion 607 ceilings for prospective sales, which are bottomed on a cost estimate of

[32] Docket No. AR70-1, Testimony of J. Rhoads Foster, Appendix, p. 10.

[33] Exhibit No. 63 (Sherwin), attached hereto as Appendix D.

17.2 cents,[34] are unreasonably low and would not provide the required cash flow.

The method used in deriving the rate recemmendations herein, flows logically from the Commission's reevaluation (Opinion 595 and 598) of the basic assumptions implicit in its prior approach to area rate-making. These Opinions correctly recognized that flowing gas prices play an important role in providing the capital needed for an adequate exploration program. The Commission in effect acknowledged that it was inappropriate to establish prices for flowing gas on the basis of a historic cost of service. It stated:

> "The funds to support exploration for and development of new gas supplies come for all gas sales. Traditional costing methods of flowing gas provide for the replacement, at historic cost levels of gas produced in the current year, which does not pro- for the replacement, at historic cost levels, of gas vide any support for the presently needed exploratory effort to meet future demand." (Opinion 598, p. 60)

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Finally, Respondents make the foregoing recommendation of price levels to be established on rehearing in the context of the following considerations:

> (1) Prices at the recommended levels are appropriate only in the absence of a moratorium. If a moratorium is to be established, even higher rates should be prescribed, to provide assurance that prices currently adequate will not be eroded by cost increases during the term of the moratorium.

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[34] Opinion 607 used the Examiner's ceilings for post 1/1/61 gas with two half-cent escalations to derive prices for the period beginning 10/1/68.

(2) Prices at the recommended levels should be established with full understanding that the natural gas industry is in an unprecedented state of transition from a status of relative abundance of gas supplies to a period of indefinite and undefined total energy shortage. In such circumstances, it should be understood that these recommended rates should be the subject of continuing surveillance as to adequacy in light of current supply conditions.

V. THE RATE ORDER SHOULD BE CLARIFIED AND MODIFIED IN CERTAIN RESPECTS

A. Deliveries From Newly Discovered Reservoirs on Committed Acreage Should Receive the Price and Other Rate Treatment Corresponding to the Date of Discovery and the Date of Delivery

In Opinion 567 the Commission established the principle that later vintage prices should be applied to later discovered sources of gas, even though acreage covering such gas had been previously contracted (42 FPC 726). In the instant Opinion however, the Commission failed to implement important aspects of Opinion 567 principles.

Section 157.40 of the Commission's Regulations and Section 2.56, Part 2, Statements of General Policy and Interpretations, should each be amended to provide for application of the principles of Opinion 567 to the Other Southwest Area. These amendments should cover at least two points.

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The first is, that the principles involved should apply to each time period over which deliveries have been made, as well as being applicable to contracts dated within

certain time periods. To illustrate, under a contract dated prior to January 1, 1961, covering a sale from Other Oklahoma, if a new reservoir were discovered after January 1, 1965, deliveries therefrom would be entitled to an 18.9-cent price for the period January 1, 1965 through September 30, 1968, and 19.4 cents for the period October 1, 1968 until January 1, 1972.

The Commission has established the principle that casinghead gas should receive the same price treatment as gas-well gas (p. 29). Accordingly, amendment of the Commission's regulations dealing with newly-discovered reservoirs on previously committed acreage should provide for collection of the price applicable to the vintage of discovery and the vintage of delivery for casinghead gas as well as for gas-well gas. Similarly, newly-discovered casinghead gas reserves should be considered new commitments under any refund discharge provision.

The Commission adopted both of these principles in Opinion 595-A in the *Texas Gulf Coast* case at page 2.

B. The Btu Gap Should Be Eliminated

The Commission erred in continuing the existence of the Btu gap, which is contrary to the public's best interest. With the exception of the minimum standard set for Mississippi and Alabama of 950 Btu per cubic foot, the Commission here has set 1,000 Btu per cubic foot as the minimum standard for downward adjustments.

The producers recommended the use of this generally accepted contract base for Btu content, for the purpose of both upward and downward adjustment for all of this hearing area with the exception of Mississippi (50: 5352-54). It represents an established practice in the industry and is a well-accepted quality standard.

However, the Commission continued the existence of the gap between the minimum and maximum standards by setting the maximum standard at figures ranging from 1,030 in the Texas Railroad Dis-

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tricts 5 and 6 and Northern Louisiana and Southern Arkansas; and 1,060 in the Other Oklahoma, Texas Railroad District No. 9 and Northern Arkansas.

The basic purpose of the Btu adjustment is to reflect the relationship between the price of natural gas and its value as a fuel; and, because of the importance of the heating content of the natural gas, to act as an encouragement to leave the heavier hydrocarbons in the gas stream.

In Opinions 464, 468, and 546, the Commission found, in view of the fact that gas is purchased for its energy content, a Btu adjustment to be appropriate. In the Btu case, the Commission stated its principal reason for this finding, which was as follows:

> ". . . It is clear, however, that unless the pipeline is in a position to offer a reasonable premium for the higher Btu gas, the producers will have a strong economic interest to extract the high Btu hydrocarbons from their gas before delivery to the pipeline. Where the producer is too small to perform this function for itself, it would, where feasible, utilize the extraction facilities of the larger producers. Under these circumstances, an appropriate upward Btu adjustment provides the necessary inducement for producers making it possible for the pipelines to acquire the supply of high Btu gas required for blending without which a large supply of low Btu gas could not be brought into the interstate pipeline system. Accordingly, we hold that the upward clauses

> here in issue are reasonably required by the public convenience and necessity for these areas." (33 FPC at 1235)

The primary objective announced by the Commission in allowing Btu adjustments would be defeated to the extent that the "gap" exists.

The finding by the Examiner in his Initial Decision in this proceeding, that the data used as the basis of Witness McCarrick's Exhibits 52 (20:2632-33) and 53 (20:264) is "adequate", was misleading and clearly erroneous. The information contained in Exhibits 52 and 53, based upon the Staff's ACD questionnaire, was proved by the industry to be imprecise (39:4244-45), included portions of

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volumes produced from outside the hearing area, and was described by the Staff's own brief as "the best available approximations" (p. 184).

Even if all the defects in compiling and compositing data to determine the weighted average Btu level of the "zone of average gas" can be overcome, one basic defect will always remain, which prevents the use of these levels as standards from which to make price adjustments. Btu levels for any given area will change from year to year as new reserves are discovered and old fields depleted. This fact is acknowledged in the Examiner's Opinion, p. 103-4, wherein he states:

> "Furthermore, the record discloses that over time, it is to be expected that the weighted average Btu content for each of the pricing areas will change 'to some extent', but not 'a great deal.'" (39:4264)

In this case, Staff Witness McCarrick testified that he had made no studies to determine whether any large vol-

ume change would distort his "zone of average gas" (39: 4265). The "zone of average gas" being based on these Btu levels, would necessarily present a different set of calculations and results for each different set of figures on which it might be based.

C. The Commission Should Modify and Correct Opinion 607 As to Quality Standards

The Commission should modify its provision on Quality Standards, paragraph 43, page 30, and the subsequent appropriate ordering provision, by providing that the Quality Adjustments, for items other that the Btu Adjustment, shall apply only to contracts dated after January 1, 1972, the effective date of the Opinion.

In Opinion 595, *Texas Gulf Coast*, the Commission adopted the Quality Standards provided for in the Examiner's Initial Decision, "for contracts executed on or after August 1, 1971 . . ." (paragraph 131, p. 48). This precedent should be followed in the instant Opinion.

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The provisions agreed to by the parties should govern contracts entered into before the effective date of this Order.

D. The Standard For Delivery Pressure Should Be Modified

In ordering paragraph (d) (2) (vi), the Commission established the following pressure standard:

> "*Delivery Pressure:* The gas shall be delivered at a pressure sufficient to enter the buyer's pipeline except that a minimum of 500 psig must be available at the point of delivery."

The 500 psig requirement does not take into consideration those situations where the purchaser does not have a line pressure as great as 500 pounds, nor where it does not need gas at that pressure. A producer should not be penalized in price on sales to pipelines if the pressure is sufficient to permit the gas to enter the purchaser's line, or if the delivery is at a pressure previously contracted for between the parties.

The Commission should modify this standard on rehearing by providing language similar to that used in Opinion 595-A, p. 10.

E. A Date Certain Should Be Established for Termination Of Interest Calculations On Refunds

The Refund Reports required under the Commission's Opinion also require that interest shall be calculated to the date of the Refund Report (Ordering Paragraph (F) (v), p. 44). Such a requirement creates problems from both administrative and practical standpoints. If the date that the Refund Report is filed falls on any date other than the end of a month, extensive computations are required fractionating production volumes and revenue data into partial months. Further, an interest calculation based on a date uncertain requires a guess as to the date the Refund Report will be completed and will, in fact, be filed with the Commission.

A better procedure would be to establish a date certain for the calculation of interest such as the effective date of these area rates,

January 1, 1972. This procedure was followed in *Southern Louisiana* (Opinion 598 and proved to be satisfactory

to all parties. In the alternative, the Opinion should be modified to provide for the calculation of interest up to and including the last day of the month preceeding the month in which the Refund Report is filed.

F. Adjustment of Applicable Area Rates For New Or Additional Taxes

The Commission failed to provide for future adjustments to applicable area rates for any new or additional state or federal production, severance, gathering, or similar taxes. In so doing, the Commission has substantially departed from its Opinions 586, 595 and 598.

It is requested that the Commission rectify this oversight and, consistent with the precedent established, modify Ordering Paragraph (A) (c) accordingly, so as to protect the adequacy and stability of the applicable area rates for the future during the period to time this Opinion is in effect.

The Commission can accomplish this goal by amending Ordering Paragraph (A) by adding: "(d) (4) The applicable area rate shall be adjusted upward or downward to reflect any change in state or federal production, severance, gathering, or similar taxes effective after January 1, 1972." While Opinion 595 and 598 allowed an 87.5 percent adjustment, there is no reason not to allow full tax reimbursement.

G. Applicable Area Rates May Be Adjusted to Reflect Changes in Btu Content

It is requested that Ordering Paragraph (E) (p. 42) be modified and clarified by adding a new sub-paragraph (4) to provide that adjustments in rates attributable to changes in Btu content shall be computed by the applicable formula and changed without the necessity of filing a notice of change in rates.

This will be consistent with the action of the Commission on rehearing in *Southern Louisiana*, Opinion 598-A.

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H. The Date Established for Filing of Refund Reports Should be Extended to April 1, 1972

The Commission's Opinion requires the filing of Refund Reports by producers by February 1, 1972 (Ordering Paragraph (F), p. 43). This filing date should be extended to April 1, 1972.

The reasons for this date extension are twofold. First, since the effective date of the base area rates is January 1, 1972 (p. 36), the Refund Report must cover volumes delivered during December, 1971. Due to the lag in gas measurement and accounting, the producers will not be fully informed of December volumes produced and the revenues attributable thereto, until around the end of February. In instances where a producer is a non-operator in a unit, a further lag is involved in receiving such information from the unit operator who, in turn, has to receive it from the pipeline purchaser.

Secondly, the date for filing Rate Schedule Quality Statements is February 1, 1972 (Ordering Paragraph (E), p. 42). Before refunds can be computed, the applicable area rates must be agreed upon as reflected on the Quality Statements executed by the pipeline purchaser and producer. It would seem reasonable to expect that, with the holiday season and concomitant mail delays occuring during the period from the date the Opinion was issued to the date Quality Statements are due, the full time allower for the completion of such Quality Statements will be required by pipeline purchasers and producers. Therefore it would be very difficult, if not im-

possible, to complete the Refund Reports in time to meet the February 1, 1972 date.

I. The Commission Should Clarify That No Refunds Will Be Required Below A Settlement Rate Approved By Final Order of the Commission Or Any Other Last Effective Rate Not Subject To A Suspension Order

The Commission indicated that it will require refunds "on amounts collected in excess of the applicable area rates for periods for which such amounts were collected subject to refund in Section 4(e) proceedings." (p. 32) The Commission then stated:

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". . . In any case where an initial price has been authorized in a final unconditional permanent certificate, amounts collected thereafter are subject to refund in a Section 4(c) proceeding only to the extent such amounts exceed the initial price. *F.P.C.* v. *Sunray DX Oil Corporation*, 391 U.S. 9, 24 (1968)." (p. 32)

In adopting the quoted language above, the Commission followed the language set out in *Texas Gulf Coast*, Opinion 595 (p. 50) which it clarified in Opinion 595-A (p. 3) to provide ". . . We agree that a rate established by a settlement approved by the Commission should be considered as a floor, for purposes of refunds. [fn. 4 Accord, *Southern Louisiana I*, 41 FPC 331 (1969). Refunds will not be required below the last effective rate not subject to suspension order.]"

The Commission in *Southern Louisiana II*, Opinion 598 (p. 78) provided: ". . . Amounts collected by the re-

spondent, even though in excess of the prices in (a) and (b), shall not be subject to refund, to the extent they were collected pursuant to a prior settlement agreement approved by this Commission, or were not in excess of a price set out in a permanent certificate issued by the Commission, or were not in excess of the refund floor provided in an applicable temporary authorization."

These holdings in *Texas Gulf Coast* and *Southern Louisiana II* are clearly required under the rationale of the Supreme Court's decision in *F.P.C.* v. *Sunray DX Oil Corp.*, 391 U.S. 9 (1968) and is equally applicable to this Opinion. There the Court resolved the issue which was argued in the *Permian I* case but not decided by either the Commission or the Court.[35] The issue involved is a construction of Section 4(e) of the Natural Gas Act, and involved the question whether by filing for a rate increase under this Section, the producer places in jeopardy only the increase applied for, or whether the entire rate collected then becomes subject to refund. The Supreme Court considered this provision of the statute in *Sunray*, and held as follows:

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> "It is true that Section 4(e) in terms gives the Commission power to report 'the portion of such increased rates or charges' found to be excessive, and does not expressly limit the refund to the rate increase or increment. However, the accounting provision, which appears earlier in the same sentence, requires that the producer account only for the 'amounts received by reason of such increase.' If it had been intended that the refund obligation should extend to greater amounts, the accounting requirement logically should have extended to them also." (391 U.S. at 24)

[35] Permian, 34 FPC at 174-75; Permian Basin Area Rate Cases, 390 U.S. at 828, n.121.

The Supreme Court did not rest its decison merely upon a technical construction of statutory language. Instead it held that the refund obligation of the producer should be limited to the amount of increase applied for. The Supreme Court stated:

> "Viewing the Act more broadly, there is another reason why this interpretation of Section 4(e) is preferable. It seems incontestable that if a producer consistently sells gas at the price specified in a final, permanent certificate, and does not attempt to increase its price, the Commission may not order it to make refunds simply because the just and reasonable rate for its area turns out to be below the in-line price. This would amount to a reparation order, and this Court has repeatedly held that the Commission has no reparation power. It would be anomalous to treat an increased price as a trigger for a refund obligation which would leave the producer with a smaller net return than if it had never increased its price at all. We therefore consider and hold that an initial price which is authorized in a final, unconditioned permanent certificate is a lower limit below which a refund cannot be ordered under Section 4(e)." (391 U.S. at 24; footnote omitted)

While the Supreme Court referred to a "final unconditioned permanent certificate" as the refund floor in the *Sunray* case because that was the type of firm rate it was dealing with in that case, the rationale above quoted is equally applicable to other firm rates, such as settlement rates finally approved by the Commission. Thus, filing of a rate increase above the settlement rate should no more place that rate in jeopardy than the filing of a rate increase above a final, unconditioned permanent certificate. In either case, the producer has

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received a firm and final order from the Commission approving its filed rate. Under the rationale of *Sunray*, this rate unquestionably constitutes a refund floor, even though the producer later elects to file a rate increase above that level.[36]

We therefore urge the Commission to clarify its Opinion on rehearing to provide that no refunds will be required below settlement rates or other rates finally approved by the Commission and follow its decision in Opinions 595-A and 598 in this respect. The Commission should modify its refund order to provide that no refunds will be required below the last effective rate not subject to a suspension order issued by the Commission under Section 4(e) of the Act.

VI. CONCLUSION

The existing natural gas supply-demand imbalance is of more critical proportion than evidenced by the Commission's Opinion 607. New supplies continue to decline, while latent demand stimulated by both the artifically low price of natural gas and its premium character, is projected to increase. Thus, volumetric requirements on the Other Southwest are greater than considered by the Commission.

The achievement of the conservative goal of new findings at 11 trillion for the Other Southwest Area over the

[36] In addition to the Sunray case, the following cases also support the proposition that the "last firm rate" is a refund floor: United Gas Pipe Line Company v. Mobile Gas Service Corp., 350 U.S. 332, 340-42 (1956); Sunray Mid-Continent Oil Corporation v. FPC, 364 U.S. 137, 145 (1960); Associated Oil & Gas Co. v. FPC, 280 F.2d 31, 34 (5th Cir. 1960; Mississippi River Fuel Corporation v. FPC, 202 F.2d 899, 902 (3d Cir., 1953).

next five years is questioned by the Commission. Noting that "major producers have decreased their activity as they seek more rewarding prospects elsewhere," the Commission alluded to declining productivity in established producing areas (p. 10). Clearly these factors dictate substantially higher prices. However, the Commission chooses to stabilize the current shortage, by "reducing" (p. 12), but not reversing the "decline in exploration for and development of gas reserves." (p. 12) [37]

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The Commission generally recognizes the current shortage of natural gas, the historic inadequacy of prices, and the undeveloped but nonetheless potential reserves in the Other Southwest. Respondents urge, however, that the Commission has erred in its determination of the extent of price rise required to relieve the supply-demand imbalance.

To realize this greater supply of gas reserves for future consumption, the incentive to explore and drill for potential supplies in the Other Southwest must be substantially increased. Because these new discoveries will be made mainly at greater drilling depth and in the risky offshore environment, each new discovery will tend to be more costly than the previous discovery. Stated another way, natural gas in an exhaustible natural resource where each increment discovered tends to be more difficult and costly to find than the last. Because the scale of exploration required is unprecedented in the industry's history, so is the scale of capital investment required. According-

[37] This position is the antithesis of that taken in Opinion 598, where it was said: "Our minimum objective has to be action to halt and hopefully to reverse the downward trend of the reserves-to-production ratio." (Op. 598, p. 31)

ly, the regulatory policy steps which must be taken to assure that such incentives are provided must be imaginative and unprecedented. In Opinion 607 the Commission erred in failing to take those steps.

On the basis of the foregoing argument and authorities, Respondents request that the Commission grant rehearing of its Opinion 607, and upon reconsideration thereof, to modify such Opinion to correct the errors specified herein.

Respectfully submitted,

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VERIFICATION

STATE OF TEXAS)
) ss
COUNTY OF HARRIS)

Thomas G. Johnson, being first duly sworn, deposes and says that he is an attorney for Shell Oil Company, that he has read the foregoing, that the facts alleged in the foregoing Application for Rehearing are true and

correct to the best of his knowledge, information and belief, and that he has been duly empowered and authorized to subscribe said Application and to execute this verification on behalf of each of the indicated producer respondents.

/s/ THOMAS G. JOHNSON
THOMAS G. JOHNSON

Subscribed and sworn to before me this 24th day of November, 1971.

/s/ DELIA GONZALEZ
DELIA GONZALEZ
Notary Public in and for
Harris County, Texas

[SEAL]

My Commission Expires
June 1, 1973

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding in accordance with the requirements of § 1.17 of the Rules of Practice and procedure.

Dated at Houston, Texas this 24th day of November, 1971.

/s/ THOMAS G. JOHNSON
THOMAS G. JOHNSON

Of counsel for
SHELL OIL COMPANY

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APPENDICES A THROUGH D

[12,262]

APPENDIX A

CALCULATIONS OF NEW GAS COST ESTIMATES AS SET OUT IN APPLICATION FOR REHEARING OF INDICATED RESPONDENTS IN DOCKET NO. AR64-2

In Opinion 607 the Commission indicated its reliance on the current cost computation in Opinion 595. Respondents in the Application for Rehearing of Indicated Respondents in Docket No. AR64-2 pointed out the errors in that computation. We herein adopt those portions of the said Application dealing with such computation, and for convenience reproduce same as this Appendix A.

1. Drilling Costs

Opinion 595 (p. 22) adopts gas-well drilling costs ranging from $19.55 per foot (the 1961-1968 average of costs reported by JAS) to $24.66 per foot (the "adjusted" 1967 Census figure trended to 1969 by reference to JAS data). For dry holes (p. 30), the drilling cost figure used is $11.25 per foot (the "adjusted" 1967 Census figure trended to 1969). The drilling cost levels seriously understate the cost of drilling as of the year 1969; they can in no sense be considered representative of the drilling costs to be anticipated for the future nor are they appropriate for use in an economic costing model.

A "credible range" of gas-well drilling costs per foot for the purpose of estimating the range of new-gas costs would be $25.48 to $30.00. For dry holes, a similar range would be $13.23 to $15.50 per foot. We discuss, first, the indicated level of drilling costs as of 1969 and, second, the anticipated drilling cost levels for the future.

The figure of $19.55 for gas-well drilling costs per foot, adopted as the lower limit of the range, has no relevance to a costing model appropriate for the year 1969, to say nothing of the future. This is clearly demonstrated by an examination of the trend of drilling costs over the past decade, as indicated by available data sources.

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Year	JAS	AR69-1, Exhibit 58	Census, Excluding Lease Equipment, Excluding Smallest Companies [a]
1961	$17.65	$17.74	
1962	18.10	17.80	
1963	17.19	17.33	$17.66
1964	18.57	18.65	
1965	18.35	18.75	
1966	21.75	21.84	
1967	23.05	23.74	24.34
1968	24.05	24.41	
1969	25.58	25.48	

[a] 1967 Census of Mineral Industries; the figures exclude single-unit establishments with fewer than five employees. The published figures covering 1963 include lease equipment costs beyond the Christmas tree. Such costs were deducted using the ratio of such lease equipment costs to total costs for all companies.

The figure of $19.55, the average of JAS costs for 1961-1968,[17] is substantially below the costs which have been incurred at any time over the past five years. Over this period, the proportion of total footage drilled to deep formations increased significantly; the relative impor-

[17] We note that the opinion did not fix the bottom of the dry-hole cost range using a technique parallel to that employed for gas wells. Had it done so, the "bottom" would have been $11.46 compared with its "top" of $11.25.

tance of high-cost offshore drilling rose dramatically; and the cost of input factors surged as a result of the general price inflation in the economy.[18] It would be wishful thinking to assume that we will see the pre-1965 drilling cost levels once again.

The opinion (p. 19) specifically refers to certain Respondents' contention that the drilling-cost figure used should not refer to a single

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year but should reflect the average experience over a period of years. We assume that the Commission's determination to use the 1961-1968 average gas-well cost per foot at the bottom of the credible range is designed to reflect such an average. However, the context in which the earlier argument was made (Respondents' Brief on Exceptions, AR64-2, pp. 44-48) was completely different from that of the Commission's present costing model. The Examiner's Initial Decision used the current-cost estimates as a basis for establishing ceiling prices for all gas sales under contracts dated on or after January 1, 1961. In determining the cost estimate, the Examiner used the 1963 Census drilling cost. The available data showed that the 1963 costs were substantially lower than in either prior or subsequent years (*supra*) and that the drilling "mix" for 1963 was atypical. In these circumstances, certain respondents in AR64-2 concluded that

[18] JAS data show that average depth of gas wells increased from 5,552 feet in 1965 to 6,034 feet in 1969 and that the proportion of total footage in wells 15,000 feet or deeper rose from 6.7% to 10.3%; offshore footage accounted for 5.2% of the 1965 drilling but for 10.4% of 1969 footage. The evidence in Docket No. AR69-1 showed that the rise in the cost of input factors from 1965 to 1969 was 16.3% and the cost increase attributable to the change in the drilling "mix" was 16.7% over the same period (Ex. 58, Sch. 8).

the 1963 costs were not representative and that the cost figure adopted should be an average of the experience of several years.

The present context is completely different. The Commission is seeking to estimate the "credible range" of new-gas costs in order to develop an economic costing model. The "economic cost" thus estimated is used to fix ceiling prices for gas sales for the *future*, *i.e.*, under contracts dated on or after October 1, 1968. The data show that drilling costs have risen inexorably throughout the past decade and that the 1963 "dip" was indeed exceptional. In these circumstances, it is completely inappropriate to make use of average costs for 1961-1968 as having any relevancy for the cost-estimation process.

The appropriate starting point in deriving the "credible range" of drilling costs per foot is the per-foot drilling cost as of the year 1969, the latest year for which estimates are available. The estimates for gas-well cost for the year 1969 are $25.58 (JAS) and 25.48 (AR69-1, Ex. 58). As an alternative, the 1967 Census figure ($24.37 per foot, excluding lease equipment beyond the Christmas tree) may be trended by reference to the change shown by other data series. All of these estimates as of 1969 are substantially above the *top* of the range adopted in Opinion 595.

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The basic error in the Commission's estimating technique is the downward adjustment of the 1967 Census figures (for gas wells from $24.37 to $22.22 and for dry holes from $14.97 to $10.94) to "include the unreported drilling costs" (pp. 20, 29).[19]

[19] The "adjusted" cost were then trended to 1969 by JAS data.

As a preliminary matter, respondents note that it is inappropriate to make any adjustment of the Census data inasmuch as the Census Bureau's exclusion of data for the smaller establishments results from the fact that the data reported by such companies were of very poor quality.[20]

In any event, if the Census data are to be adjusted to include the unreported drilling, the adjustment should be made on some reasonable basis. The unreasonable nature of the adjustment made becomes apparent by examination of the per-foot costs for unreported drilling which are implicit in the opinion's estimating technique —$11.21 per foot for gas wells (excluding lease equipment) and $4.25 per foot for dry holes.[21] The assumptions made in the opinion concerning average per-foot costs for the drilling not reported by Census are in sharp conflict with the data shown in the Census report. For gas wells, 53 percent of the unreported footage was drilled to formations deeper than 5,000 feet and 11 percent to formations deeper than 12,500 feet; the Census costs range from $14.85 for wells from 5,000-9,999 feet to $50.47 for the drilling deeper than 12,500 feet.

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[20] The Census report states:

> "Because of the importance of drilling data, and since information on drilling was not available from administrative sources, a 5 percent sample of all single unit oil and gas companies with less than 5 employees was mailed a regular census schedule. However, a comparison of the data reported by these sample companies with other sources, indicates *the reporting to be of such poor quality* that it was decided to exclude these data from this census." (P. 13A-2, U. S. Bureau of the Census, Census of Mineral Industries, 1967, Crude Petroleum and Natural Gas, MIC67(1)-13A, emphasis supplied.)

[21] Derived by subtracting the Census figures for wells, footage and costs from the industry-wide totals derived using JAS wells and footages and the Opinion 595 per-foot costs.

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If the 1967 Census data are to be adjusted to include the unreported drilling, the best available technique is to take account of the distribution of the unreported drilling by depth class, using the per-foot costs as reported by Census for each depth class. Using this technique, the costs for the unreported drilling become $18.61 per foot and the cost for all 1967 drilling is $23.43 per foot.[22] Trending to 1969 by JAS results in an estimate of $26.01 per foot.

For dry holes, 55 percent of the unreported footage was at depths of 5,000 feet or more and 3.5 percent deeper than 12,500 feet; the costs reported by Census range from $10.89 at 5,000-9,999 feet to $36.35 for drilling at 12,500 feet or deeper. Using the same estimating technique as for gas wells, the cost of the unreported

[22] The estimate for gas wells is obtained as follows:

Depth (Feet)	Unreported Footage (000's) (a)	Census Cost Per Foot Reported Wells (b)	Estimated Costs [(a) x (b)] (Million $) (c)
Up to 2,499	608	$11.56	7.0
2,500 - 4,999	1,203	12.10	14.6
5,000 - 9,999	1,482	14.84	22.0
10,000 - 12,499	124	28.09	3.5
12,500 and over	426	50.47	21.5
Total not reported by depth	3,843		68.6
Included in Census totals, not reported by depth	(280)		(2.3)
Total not reported	3,563		66.3
Total reported	18,199		443.5
Total	21,762		509.8

Cost Per Foot, Unreported Drilling = $18.61
Cost Per Foot, Total Drilling = $23.43

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drilling is $10.33 and the cost of all 1967 dry-hole footage is $13.23 per foot.[23]

Thus, the Commission's estimates of the costs for drilling not reported by Census imply that the small nonreporting producers drill gas wells at a cost 40 percent lower than the costs incurred by the reporting companies at comparable depth ($11.21 vs. $18.61) and drill dry holes at comparable depth at a cost 59 percent lower ($4.25 vs. $10.33). It is inconceivable that the large companies, with their great technical expertise and large-scale operations, would be outperformed by the smaller companies. Any assumption that the small companies do drill at lower cost must rest on acceptance of the dubious 1963 Census data. However, the contention that the 1963 Census costs were seriously understated, especially for

[23] The estimate for dry holes is obtained as follows:

Depth (Feet)	Unreported Footage (000's)	Census Cost Per Foot Reported Wells	Estimated Costs [(a) x (b)] (Million $)
	(a)	(b)	(c)
Up to 2,499	3,107	$ 5.50	17.1
2,500 - 4,999	7,638	5.70	43.5
5,000 - 9,999	10,731	10.89	116.9
10,000 - 12,499	1,728	21.84	37.7
12,500 and over	842	36.35	30.6
Total not reported by depth	24,046		245.8
Included in Census totals, not reported by depth	(611)		(3.7)
Total not reported	23,435		242.1
Total reported	38,375		582.0
Total	62,310		824.1

Cost Per Foot, Unreported Drilling = $10.33
Cost Per Foot, Total Drilling = $13.23

the small producers is confirmed by the Bureau of the Census decision not to include drilling data for the smallest companies in the 1967 report because of the poor quality of the reporting.

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To the extent that the Commission's estimates of the cost of the drilling not reported to Census were based on the average depth of such drilling (4,049 feet for gas wells and 3,793 feet for dry holes), the estimates are also erroneous. Average depth in itself provides no basis for estimating drilling costs. It is also necessary to consider the distribution of drilling by depth range.[24]

A clear indication of the unreliability of the adjustment technique underlying the drilling cost figures used in Opinion 595 is found in the FPC Staff Reply Brief in Docket No. AR69-1. The New York Public Service Commission had adopted drilling cost figures for 1969 of $24.34 for gas wells (only slightly below the "top" Opinion 595 figure of $24.66) and $12.98 for dry holes (substantially above the figure of $11.25 used in Opinion 595). FPC Staff, in rebuttal, stated:

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[24] To illustrate, assume the two alternatives shown below:

		Alternative A			Alternative B		
Well Depth	Typical Cost/Ft	Number of Wells	Total Footage	Total Cost	Number of Wells	Total Footage	Total Cost
2,000′	$10.00	5	10,000	$100,000	9	18,000	$180,000
6,000′	13.00	5	30,000	390,000	—	—	—
14,000′	40.00	—	—	—	1	14,000	560,000
		10	40,000	$490,000	10	32,000	$740,000
		Average Cost		=$12.25	Average Cost		=$23.13
		Average Depth		= 4000′	Average Depth		= 3200′

The average depth is higher for Alternative A than for Alternative B. But with the "drilling mix" shown for Alternative A, the average cost is $12.25 per foot, while the Alternative B "drilling mix" yields an average cost of $23.13 per foot.

". . . The procedures recommended by New York must be considered an unreasonable torturing of the available data in order to arrive at the lowest possible drilling cost. The staff cannot agree with the suggestions of New York and believes the drilling costs calculated and recommended by New York substantially understate actual 1969 drilling costs." (Staff Reply Brief, AR61-2 and AR69-1, p. 43)

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As of 1969, the lowest "credible" drilling costs are *$25.48* for gas wells and *$13.23* for dry holes. Alternative estimates range up to $29.95 for gas wells and $16.17 for dry holes.[25]

The remaining question is the upper limit of the "credible" range of gas-well drilling costs in the context of an economic costing model. Opinion 595 states that "for a costing model for the future, we are justified in selecting a drilling figure on the high side of the indicated range" (p. 32). Respondents concur. It is regrettable that this theory was not translated into practice in the decision.

All witnesses who have testified in recent FPC proceedings with respect to drilling costs are unanimous in their anticipation that costs per foot will continue to in-

[25] The alternative estimates are as follows:

	Gas Wells	Dry Holes
JAS	$25.58	$13.23
Witness Gody AR69-1, Ex. 58)	25.48	14.00
Census, unadjusted, trended to 1969		
Using 1967-69 JAS change	27.05	15.39
Using 1967-69 change shown by respondents in AR69-1	29.95	16.17
Census, adjusted, trended to 1969		
Using 1967-69 JAS change	26.01	13.60
Using change shown by respondents in AR69-1	28.80	14.29

crease in the future as a result of continued inflation in the economy and as a result of the ever-increasing emphasis on deeper drilling and on offshore drilling. In light of these anticipations for the future, it is reasonable to adopt as the upper limit of the "credible range" an estimate of $30.00 per foot for gas wells and $15.50 per foot for dry holes. The $30.00 per foot estimate for gas wells is only slightly above the upper limit of the estimate of *1969* drilling costs and 17 percent above the lower limit. The increase in drilling costs over the period 1963-1969 was at an average rate of 6.6 percent annually. Assuming a similar rate of increase in drilling cost levels after 1969, the estimated $30.00 per foot cost would be applicable for the period mid-1971 to mid-1972. Thus, the $30.00 cost for gas wells is virtually a "current" cost estimate even if one adopts the lowest of the credible estimates of per-foot costs experi-

enced in the year 1969. Similar considerations apply for the dry-hole costs.

2. Successful Well Costs

Opinion 595 uses drilling costs of $19.55 to $24.66, in conjunction with productivity estimates ranging from 602 Mcf per foot (the average for 1947-1969) to 723 Mcf (the average for 1964-1968) to derive successful well costs ranging from 2.70 to 4.10 cents. As indicated above, the appropriate drilling cost range is $25.48-$30.00. The appropriate productivity figure is no higher than 600 Mcf per foot. The average for the last ten years is 599 Mcf and the average for the entire period since 1947 is 602 Mcf per foot. Moreover, as indicated by the opinion

at page 32, productivity may be expected to decline with increased drilling activity. A five-year period is too short for use in estimating productivity levels; as indicated by the table at page 21 of the opinion, a one-year shift in the five-year period used results in a 10 percent differential. Moreover, as is also evident from the table at page 21 of the opinion, the figure of 723 Mcf for 1964-1968 is the highest for *any* five-year period of record.

Using per-foot drilling costs of $25.48-$30.00 per foot, in conjunction with productivity of 600 Mcf per foot, successful well costs are computed as 4.25-5.00 cents per Mcf.

3. Lease Acquisitions

The questions concerning lease acquisitions include data source, time period, and basis of allocation of total lease costs between oil and gas. The lower range of the Commission's estimates combines data for the 1963-1967 period of relatively low aggregate lease acquisition costs ($558 million annually, compared with $709 million annually for 1961-1968) with data for the 1964-1968 period of high productivity (the highest of *any* five-year period for which statistics are available).

The lower estimate of the range of lease acquisition costs should be 33.4 percent of the total of such expenditures during 1961-1968

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(compared with the 43% figure used in the opinion for the top of the range.)

4. Other Production Facilities

Opinion 595 states that the estimation of this component as 17.33 percent of successful well cost yields a

range of .31 to .50 cents per Mcf. However, the costs derived by the use of the 17.33 percentage using the opinion's successful well costs, are in fact .47 to .71 cents. Apparently, the Commission deducted from the costs thus derived an amount representing about 5.6 percent of successful well costs. Such a deduction is erroneous. The Examiner's Initial Decision made a deduction of this kind for the reason that the drilling cost figure used there included a certain amount of lease equipment beyond the Christmas tree. The drilling cost figures used in Opinion 595 (and the alternative data proposed by Respondents herein) do not include such lease equipment. Application of the 17.33 percent factor to successful well cost yields estimates of .74 and .87 cents; the alternative technique discussed in the opinion results in the estimate of .73 cents. The cost range is thus estimated as .73-.87 cents per Mcf.

5. Dry Holes and Other Exploration Costs

Use of dry-hole drilling costs ranging from $13.23 to $15.50 per foot in conjunction with the productivity figure of 600 Mcf, other aspects of the opinion's computational techniques being unchanged, results in dry-hole costs of 2.31 to 2.71 cents.

With respect to Other Exploration Costs, the procedure followed in the opinion applied to the Respondents' alternative estimates of the cost components heretofore discussed yields costs ranging from 1.79 to 2.28 cents per Mcf.

6. Adjustment for Exploration in Excess of Production

Respondents are completely unable to fathom the rationale underlying the Commission's determination not to include any adjustment for exploration in excess of pro-

duction. Opinion No. 595 states: "If we adhere to the basic concept of economic costing, as includ-

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ing the costs of eliciting supplies sufficient to meet the demand, then we have little or no need for special allowance categories" (p. 28). The opinion also points out that in *Permian* the adjustment for exploration in excess of production was based not on the level of exploration desired, but on the level of exploration which had actually occurred in the past (see *e.g.*, 34 FPC at 193-94). These brief comments provide no clue to the Commission's thinking on this important question.

The adoption of an economic costing concept compels the conclusion that an adjustment is in fact required for exploration in excess of production, not the contrary. The use of an economic costing concept means that the Commission must estimate the cost which will be incurred to elicit a desired level of supply additions. The costs which will be incurred include the expenditures for dry holes and other exploratory costs. The price (or cost) which is established must be sufficient to enable the producers to recoup such expenditures. If the Commission has concluded that it desires to elicit new supply additions in excess of production on a nationwide basis, then it must adopt one of two alternatives:

(i) Assuming the theory that such exploration expenditures should be recouped out of current-year production revenues, the new-gas cost estimate must include an allowance for exploration in excess of production. In other words, the exploration expenditures which are initially expressed in cents per Mcf of reserve additions must be restated in cents per Mcf of production. To illustrate, if ex-

ploration expenditures amount to five cents for each Mcf of new supply and if the new supply desired is 1.5 times productions, the price (cost) must allow for the recoupment of 7.5 cents for each Mcf produced.

(ii) Alternatively, if one were to adopt the theory that exploration expenditures should not necessarily be recouped out of current-year revenues but should be recouped over a period of years (*i.e.*, that exploration expenses should be

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treated as though capitalized), then the Commission must allow a return on such costs and must make a determination concerning the appropriate time period over which return should be allowed for the recoupment of such expenditures.[26]

Assuming adoption of the first alternative, the adjustment for exploration in excess of production should reflect the level of exploration desired—*i.e.*, should be based on the F/P ratio which the Commission seeks to achieve. Opinion 595 does not establish goals on a nationwide basis with respect to the desired F/P ratio.

Absent a Commission determination of the desired level of supply additions on a nationwide basis, Respondents are unable to recommend the appropriate adjustment for exploration in excess of production. For the present purpose, a reasonable adjustment may be derived by using at least a ratio of 1.37 as adopted in *Permian* (34 FPC at 193-94).

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[26] The opinion recognizes this problem in the comment (p. 25) concerning "basic questions" of whether exploratory costs should be treated as expenses in the year incurred and, if not, what time period should be used for their recovery.

7. Royalty

Opinion 595 is silent with respect to the appropriate royalty percentage to be included in the cost computation; the table showing the cost of new gas-well gas (p. 34) indicates only that royalty is a derivative of the total price of gas. In Opinion 546 the Commission used a royalty cost of 14 percent based on AAQ data for royalties of all vintages of gas (40 FPC at 587). However, data which became available in Docket No. AR69-1 with respect to royalties of recent-vintage gas indicate that the appropriate royalty percentage is substantially higher.

Dr. Sherwin concluded, on the basis of his analysis of the recent data, that the appropriate royalty percentage is in the range of 15.5-16.5 percent (Initial Brief of Indicated Respondents, AR61-2 and AR69-1, p. 115). The Commission should adopt this range.

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8. Summary

In the table which follows, respondents show the Opinion 595 cost adjusted only for the cost components discussed above. With these adjustments, the cost estimate becomes 25.46-33.16 cents per Mcf, exclusive of state production taxes. Inclusion of the Texas tax of 7.5 percent results in a cost range of *27.52* to *35.85* cents per Mcf.

COST OF NEW GAS-WELL GAS

Cost Elements	Opinion No. 595 Variable Cost Range	Adjusted [28]
DD&A		
Successful well costs	2.70 — 4.10¢	4.25 — 5.00¢
Lease Acquisitions	1.13 — 2.03	1.58 — 2.03
Other Production Facilities	.33 — .73	.73 — .87
E&D		
Dry Holes	1.64 — 1.97	2.31 — 2.71
Other Exploration Costs	1.29 — 2.18	1.79 — 2.28
Adjustment for Exploration in Excess of Production	—	1.52 — 1.85
Production Operating Expense	3.11	3.11
Return on Production Investment	6.24 —10.29	9.84 —11.85
Return on Working Capital	.47 — .72	.65 — .81
Net Liquid Credit	(4.41)—(4.10)	(4.41)—(4.10)
Regulatory Expense	.14	.14
Subtotal	12.64—21.17	21.51—26.55
Royalty	Derivative	3.95 — 5.25
Total, excluding production tax		25.46 —31.80
Production Tax (7.5%)	Derivative	2.06 — 2.58
Total, including production tax		27.52 —34.38

Note: The costs exclude gathering and delivery.

[28] The adjustments made are specified in the text. The use of 15.5 to 16.5% royalty would result in some change in Production Operating Expense and Net Liquid Credit; these changes are largely offsetting and have been ignored in the computation.

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APPENDIX B

ESTIMATED CURRENT NATIONWIDE COST OF FINDING AND PRODUCING NONASSOCIATED GAS: WITNESS SHERWIN'S PRESENTATION IN DOCKET NO. AR69-1 ADJUSTED FOR CHANGE IN DRILLING COSTS

Line No.	Items	Range			
		Low		High	
		At 15% Return	At 16% Return	At 15% Return	At 16% Return
		(Cents per Mcf at 14.65 Psia)			
1.	Successful Well Costs	4.65		5.02	
	a. Recompletions and deeper drilling	.21		.23	
2.	Other Production Facilities	.88		1.28	
3.	Lease Acquisition Costs	2.17		2.53	
4.	Return on Foregoing Investment	12.28	13.10	15.65	16.69
5.	Dry Holes	2.32		2.75	
6.	Other Exploratory Costs	1.85		2.53	
7.	Adjustment for Exploration in Excess of Production (37%)	1.54		1.95	

8. Production Operating Expense	2.88		3.06	
9. Return on Working Capital	.75	.80	.88	.93
10. Net Liquid Credit	(3.99)		(3.93)	
11. Regulatory Expense	.17		.17	
12. Subtotal	25.71	26.58	38.12	33.21
13. Royalty	4.72	4.88	6.35	6.56
14. Total, Excluding Production Taxes	30.43	31.46	38.47	39.77
15. Production Taxes (7.5%)	2.47	2.55	3.12	3.22
16. Total, Including Production Taxes	32.90	34.01	41.59	42.99

Source: Docket No. R-425, Exh. No. —— (CSG-1), Celia Star Gody. The basic cost components are from Docket No. AR69-1, Exh. No. 63 (Sherwin) with drilling costs increased by 10 percent. The low end of the range reflects an 18-year depletion period, 1½ years time lag and 15.5 percent royalty; the high end reflects a 20-year depletion period, 1-2/3 years time lag and 16.5 percent royalty.

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APPENDIX C

ESTIMATED COST OF NON-ASSOCIATED GAS
1961 - 1968

(Cents per Mcf at 14.65 Psia)

Year	Return at 15 Percent			Return at 16 Percent		
	Total, Excluding Production Taxes	Production Taxes at 7.5%	Total, Including Production Taxes	Total, Excluding Production Taxes	Production Taxes at 7.5%	Total, Including Production Taxes
	(a)	(b)	(c)	(d)	(e)	(f)
1961	22.04	1.79	23.83	22.79	1.85	24.64
1962	21.64	1.76	23.40	22.38	1.81	24.19
1963	23.24	1.88	25.12	24.02	1.95	25.97
1964	23.60	1.91	25.51	24.40	1.98	26.38
1965	24.07	1.95	26.02	24.89	2.02	26.91
1966	27.01	2.19	29.20	27.92	2.26	30.18
1967	29.01	2.35	31.36	30.01	2.43	32.44
1968	30.23	2.45	32.68	31.27	2.54	33.81
Average 1961-1968			27.14			28.06

Source: Col. (a)—Docket No. AR69-1, Exh. No. 63 (Sherwin). Total including royalty but excluding production taxes adjusted to 15 percent return and pressure base adjusted to 14.65 psia.

Col. (d)—*Ibid.* Total including royalty but excluding production taxes; pressure base adjusted to 14.65 psia.

APPENDIX D

ESTIMATED NATIONWIDE CURRENT COST OF NON-ASSOCIATED GAS

Return at 13 Percent

1961 - 1968

	1961	1962	1963	1964	1965	1966	1967	1968
Depletion, Depreciation and Amortization of Production Investment Costs				(Cents per Mcf at 14.73 Psia)				
1. Successful well costs	3.16	3.15	3.13	3.25	3.21	3.75	3.99	4.16
2. Recompletions and deeper drilling	0.06	0.06	0.09	0.10	0.13	0.15	0.20	0.21
3. Lease acquisition costs	1.15	1.06	1.37	1.38	1.45	1.54	1.73	1.81
4. Other production facilities	0.57	0.60	0.63	0.68	0.71	0.86	0.96	1.04
5. Subtotal	4.94	4.87	5.22	5.41	5.50	6.30	6.88	7.22
Exploration and Development Costs								
6. Dry holes	1.83	1.91	1.83	1.80	1.87	2.05	2.07	2.14
7. Geological and geophysical	1.26	1.23	1.35	1.32	1.33	1.48	1.65	1.63

8. Exploration overhead	0.39	0.40	0.43	0.42	0.44	0.47	0.48	0.44
9. Adjustment for exploration in excess of production (37%)	1.29	1.31	1.34	1.31	1.35	1.48	1.55	1.56
10. Subtotal	4.77	4.85	4.95	4.85	4.99	5.48	5.75	5.77
Other Costs and Return								
11. Production operating expense	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
12. Net liquid credit	(3.61)	(3.80)	(3.57)	(3.70)	(3.68)	(3.73)	(3.91)	(3.84)
13. Regulatory expense	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
14. Return on working capital	0.44	0.42	0.48	0.48	0.50	0.53	0.57	0.59
15. Return on production investment	7.66	7.55	8.07	8.36	8.47	9.52	10.36	10.86
16. Cumulative subtotal	17.37	17.06	18.32	18.57	18.95	21.27	22.82	23.77
17. Royalty (16%)	3.31	3.25	3.49	3.54	3.61	4.05	4.35	4.53
18. Total, excluding production tax	20.68	20.31	21.81	22.11	22.56	25.32	27.17	28.30

Source: Ex. 63, Sch. 2, Sh. 1, AR69-1

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ESTIMATED NATIONWIDE CURRENT COST OF NON-ASSOCIATED GAS

Return at 16 Percent

1961-1968

	1961	1962	1963	1964	1965	1966	1967	1968
	(Cents per Mcf at 14.73 Psia)							
Depletion, Depreciation and Amortization of Production Investment Costs								
1. Successful well costs	3.16	3.15	3.13	3.25	3.21	3.75	3.99	4.16
2. Recompletions and deeper drilling	0.06	0.06	0.09	0.10	0.13	0.15	0.20	0.21
3. Lease acquisition costs	1.15	1.06	1.37	1.38	1.45	1.54	1.73	1.81
4. Other production facilities	0.57	0.60	0.63	0.68	0.71	0.86	0.96	1.04
5. Subtotal	4.94	4.87	5.22	5.41	5.50	6.30	6.88	7.22
Exploration and Development Costs								
6. Dry holes	1.83	1.91	1.83	1.80	1.87	2.05	2.07	2.14
7. Geological and geophysical	1.26	1.23	1.35	1.32	1.33	1.48	1.65	1.63

8. Exploration overhead	0.39	0.40	0.43	0.42	0.44	0.47	0.48	0.44
9. Adjustment for exploration in excess of production (37%)	1.29	1.31	1.34	1.31	1.35	1.48	1.55	1.56
10. Subtotal	4.77	4.85	4.95	4.85	4.99	5.48	5.75	5.77
Other Costs and Return								
11. Production operating expense	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
12. Net liquid credit	(3.61)	(3.80)	(3.57)	(3.70)	(3.68)	(3.73)	(3.91)	(3.84)
13. Regulatory expense	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
14. Return on working capital	0.54	0.52	0.59	0.59	0.61	0.65	0.70	0.72
15. Return on production investment	9.43	9.29	9.93	10.29	10.43	11.71	12.75	13.37
16. Cumulative subtotal	19.24	18.90	20.29	20.61	21.02	23.58	25.34	26.41
17. Royalty (16%)	3.67	3.60	3.86	3.92	4.01	4.49	4.83	5.03
18. Total, excluding production tax	22.91	22.50	24.13	24.53	25.03	28.07	30.17	31.44

Source: Ex. 62, Sch. 2, Sh. 2, AR69-1

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

APPLICATION OF MOBIL OIL CORPORATION FOR REHEARING AND RECONSIDERATION

Mobil Oil Corporation (Mobil), an aggrieved party to proceedings, pursuant to Section 19(a) of the Natural Gas Act, 52 Stat. 832, 15 U.S.C. § 717(r) (Act), and Section 1.34 of the Federal Power Commission's (Commission) Rules of Practice and Procedure, hereby respectfully applies for rehearing upon and reconsideration of Opinion No. 607 issued October 29, 1971, and the "Findings" and "Further Findings and Order" therein. in the particulars covered by this application.

In support hereof, Mobil presents specifications of error, contained herein, and states that in each instance the Commission:

1. Abused or exceeded its authority, producing arbitrary results, and
2. Made findings, conclusions or rulings contrary to law or not supported by substantial evidence.

To avoid duplicative presentations, Mobil adopts the Application for Rehearing of Indicated Respondents filed by the Major Producer Group insofar as the contents of that applica-

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tion are not inconsistent with the specification of errors and argument set forth herein.

I.

STATEMENT

Mobil is a producer respondent in these proceedings and participated throughout. Mobil commends the Commission for its recognition of "economic cost," "zone of reasonableness," the departure from rigid conversion of imprecise cost estimates into area ceiling rates, its courage in acknowledging the major problem of the need for greater capital formation in this industry, as well as other major problems confronting producers. Nevertheless, Mobil respectfully submits that the Commission continues to herald the needed regulatory reform but falls short of its achievement.

For reasons elaborated in this application, Mobil opposes the findings and conclusions in Opinion No. 607 on principal grounds that:

1. *Just and Reasonable Rates:* The Commission has established just and reasonable rates at rate levels established for other areas in prior decisions without disclosing the premise on which the rate design is based.

Mobil seeks rehearing on the grounds that the rate levels established are inadequate, the design of rate levels is not supported by the record, the rate levels do not include

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the necessary incentives or provide insufficient incentive and fail the *Austral* tests.

2. *Adjustment of Applicable Area Rate Levels for New or Additional Taxes and Assessments.* The Commission failed to provide for adjustment to area rate levels for new or additional taxes or assessments.

Mobil seeks rehearing on the grounds that error was committed in failing to provide for escalation of applicable area rate levels to compensate for future changes in taxes or assessments.

3. *Contingent Additional Royalty Payments.* The Commission failed to provide an allowance for additional royalty payments above contract price required by the Commission under Opinion No. 562.[1]

Mobil seeks rehearing on the grounds that error was committed in failing to compensate Mobil and others similarly situated for additional royalty expense by reason of Opinion No. 562.

4. *Moratorium.* The Commission has imposed a moratorium on all price increases above "applicable area rates" until July 1, 1976 (Op. 607, p 32).

Mobil seeks rehearing on grounds that this moratorium is too long, is unsupported, and is arbitrary and unlawful.

5. *Refunds.* Amounts collected in Section 4(e) proceedings in excess of the applicable area rates are subject to refund whether such proceedings are consolidate in this proceeding or not (Op. 607, p. 32). It is inconsistent, and produces arbitrary and unreasonable results to require refunds in this proceeding. Mobil seeks rehearing for such reasons.

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[1] *William Harvey Denman, Trustee, et al.*, Docket Nos. RI-67-113, *et al.*, 42 FPC 164.

II.

SPECIFICATIONS OF ERROR

1. *Just and Reasonable Rates.* In establishing the applicable just and reasonable rate levels in Opinion No. 607, the Commission has established rates which:

(a) Are inadequate to enable the Other Southwest Area to continue to supply its present share of the national interstate market;

(b) Fail to contain any incentives or provide insufficient incentives;

(c) Do not conform or fail to sufficiently conform to the applicable judicial mandates, particularly Southern Louisiana Area Rate Cases (*Austral Oil Co., et al,* v. *F.P.C.*, 428 F.2d 407 (5th Cir. 1970), cert. denied, —— U.S. ——, 27 L.Ed.2d 257 (1970);

(d) Are unreasonably low, non-compensatory, and

based upon rate levels established for other areas by prior decisions without consideration of the unique features of this area;

(e) Are insufficient because the Commission's estimate of the current cost of gas-well gas are understated and the Commission incorrectly relied on the imprecise cost findings of the Examiner in estimating the cost of flowing gas;

(f) Are unsupported by required or sufficient findings of fact;

(g) Are inconflict with, and in violation of, the standards of Sections 4 and 5 of the Act.

2. *Quality Standards.* In not allowing a proportionate upward adjustment for gas with a Btu content in ex-

cess of 1,000 Btu in sub-areas other than Mississippi and Alabama, the Commission has created an artifical gap which:

(a) Is unsupported by substantial evidence and in conflict with the prepondenance of evidence that the upward adjustment be made from the level of of 1,000 Btu per cubic foot in the same way as the downward adjustment;

(b) Is unsupported by required or sufficient findings of fact;

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(c) Is in conflict with, and in violation of, the standards of Sections 4 and 5 of the Act.

3. *Adjustment of Applicable Area Rate Levels for New or Additional Taxes or Assessments.* In failing to provide for future adjustments to applicable area rate levels for any new or additional taxes or assessments, the Commission has:

(a) Failed to protect the adequacy of the applicable area rates for the future;

(b) Departed from the Commission's Opinion No. 595-A issued October 18, 1971 in the Texas Gulf Coast Area Rate Proceeding where such increase in ceiling rates was found to be part of the just and reasonable rate for the future;

(c) Omitted a substantial finding in conflict with and in violation of, the standards of Sections 4 and 5 of the Act.

4. *Contingent Additional Royalty Payments.* In estimating the current cost of gas-well gas and in relying on the Examiner's flowing gas cost, the Commission has established rates which are:

(a) Non-compensatory in failing to compensate a producer for additional royalty expenses incurred by reason of the Commission's Opinion No. 562;

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(b) Inadequate to provide incentive, to meet desired levels of production; or to compensate producers during the moratorium imposed;

(c) Based on findings or lack of findings which are not supported or insufficiently supported by the record in this case;

(d) In conflict with, and in violation of the standards of Sections 4 and 5 of the Act;

(e) Arbitrary, capricious, and unlawful in force and effect.

5. *Rate of Return.* In providing for a rate of return of "approximately 15 percent," the Commission found a rate of return which is:

(a) Insufficient to be commensurate with returns on investments in other enterprises for corresponding risks and uncertainties;

(b) Inadequate to attract the capital necessary to meet the Commission's projections of reserve levels for this area;

(c) Insufficient to assure financial integrity of the producers, past and future;

(d) Unsupported by substantial evidence, current data and Commission "expertise" in the light of expectations as to rising costs, increased demands, intra-

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state competition and other relevant factors;

(e) In conflict with, and in violation of Sections 4 and 5 of the Act.

6. *Moratorium.* In imposing a moratorium until July 1, 1976, particularly in conjunction with inadequate current area rates and interim escalations, the Commission has imposed a moratorium which is:

(a) Unsupported by substantial evidence and in conflict with the preponderance of evidence as to expectations of rising costs, increased demands, and other relevant factors;

(b) Unsupported by required or sufficient findings of fact;

(c) In excess of a "reasonable" moratorium for this area, particularly under present economic and supply conditions;

(d) In conflict with, and in violation of, the standards of Sections 4 and 5 of the Act;

(e) Arbitrary, capricious, and unlawful in force and effect.

7. *Refunds.* In requiring refunds in this area, the Commission has imposed an inconsistent rate design which is:

(a) Arbitrary, capricious, unreasonable, and therefore unlawful in operation and effect, in that it

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is inconsistent with expressed need for additional capital formation to enable the exploration for and dedication of additional gas to the interstate market;

(b) Unsupported by substantial evidence;

(c) Unsupported by required or sufficient findings of fact;

(d) In conflict with, and in violation of, standards of Section 4 of the Act.

Other grounds for rehearing are adopted from the Application for Rehearing of Indicated Respondents insofar as the contents of that application are consistent with the contents of this application.

III.

ARGUMENT AND GROUNDS FOR RELIEF

As its basis for argument and grounds for relief, Mobil submits the following in support of its Application herein. In order to avoid cumulative applications and undue repetition, Mobil will generally adopt the arguments made by the so-called "Shell Group" on the issues insofar as the content of that application are not inconsistent with Mobil's position herein.

1. *Just and Reasonable Rates.*

(a) The Commission Erred in Prescribing Rates Which Are Inadequate to Enable This Area to Continue to Supply Present Levels of Production.

It is Mobil's position that the applicable area rates prescribed are entirely inadequate to bring forth the needed effort to meet even the present supply performance in the area as found by the Commission for the five-year period ending 1970 (Op. 607, *mimeo* p. 10). The Commission largely writes off Other Southwest Area for the interstate market because "it is not possible to set realistic goals for new dedications . . .". Although estimating the need to replace present supply to be 11 trillion cubic feet and while acknowledging that reliable estimates show far greater reserves await discovery in

the area, the Commission makes no effort to price induce the exploration required.

(b) Relative to Other Commission Areas the Inducment Here is Negative.

The Commission purports to find the following "incentives" which purportedly give rise to the conclusion that the rate levels established would bring forth the desired level of supply during the moratorium period ending July 1, 1976: (1) marginal price escalations on an industry basis; and (2) the rate levels for new vintage gas.

For those who live in the real world of gas supply, it is extremely difficult to envision the "incentive" provided by rate barely one-third of the cost of alternative fuels.[2]

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The interstate market must compete head-on with the intrastate market which consumes 40 percent to 45 percent of the gas produced in this area (Op. 607, *mimeo* p. 11). The Commission's records show that "emergency" purchases have been made by interstate pipelines in the range of 29-35 cents per Mcf. The Commission has current information available to it to provide the basis for valid judgments as to what constitutes an incentive price in this area, and yet it relies almost entirely on its decisions in other, prior opinions. Significant quantities of gas cannot reasonably be expected to be diverted from the intrastate market by sub-area jurisdictional ceiling rates ranging from 23.5 cents to 24 cents per Mcf.

In short, any Commission finding based on the so-called "incentives", which fail to include location value

[2] Exhibit —— (RLS-1), Schedule 25, Docket No. R-425.

of gas in this area, and whether considered individually or collectively, that the ceiling rates set will attract the badly needed supply to the interstate market is unsupported and erroneous. Time is running out for the Commission to provide realistic incentives to improve the natural gas supply inventory. Neither the Commission nor the consumers can afford another trial and error rate level experiment which is designed to err on the low side. Because of lead time considerations necessary to mount an expanded exploration program, further delay in establishing adequate ceiling levels

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may have disastrous supply consequences. Mobil is vitally concerned that the Commission has not fully evaluated actual market conditions in this area. Instead, the Commission has erroneously relied on only a few of the so-called "incentives" established for other areas which is unlawful under the present regulatory methodology and under the Act and is insufficient to meet the goal the Commission should have set for an expanded exploratory effort.

The seriousness of the situation is amply illustrated by the Commission's estimate that 11 trillion cubic feet of new reserves is needed for the intrastate and interstate markets in the next five years merely to maintain current levels of production. This would still not represent a desired result (Op. 607, *mimeo* p. 12). To satisfy even this undesirable result the Commission merely states that a positive impact upon exploration and development programs of producers should be provided by the rate levels prescribed here from other areas without including all the incentives it allegedly prescribed for those other areas. The result, in conjunction with re-

quired refunds, is to create a negative incentive for this area.

In summary, it is apparent that the Commission has failed to explain the relationship between level of service, the demand for service and how the price established is

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expected to achieve goals it set and should have set. A reviewing court cannot satisfy itself from the Commission's opinion that the "end-result" test has been met.[3]

(c) The Decision Does Not Adequately Meet the *Austral* Tests.

The Opinion fails to contain the necessary findings as to the impact of its order on industry structure, industry revenues, past and future, the amount or impact on the industry of refunds resulting from the order, and the industry's probable conduct and performance as a result of this order. The order thereby fails to provide an accurate assessment of supply consequences and fails to provide an assessment of the other consequences especially as to additional royalty requirements and the purported "incentive" to be derived from its rate levels.

(d) The Rates Prescribed for Flowing Gas Under Contracts Dated Prior to October 1, 1968 Are Inadequate.

Flowing gas-well gas cost estimates with reliance largely placed on the Examiner's methods are inadequate. Such fails even to offset the impact of inflation, and cannot be reasonably expected to generate the neces-

[3] *Austral*, 428 F.2d at 444, citing *F.P.C.* v. *Hope Natural Gas Co.*, 320 U.S. 591 (194).

sary capital with which even current supplies may be replaced. When coupled with

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the negative incentive provided by the refund order the conclusion reached is that Other Southwest has been written off as an area in which only the intrastate market is to be served in the future. Furthermore, the Commission failed to include any analysis of the impact on capital formation of its recent Order No. 441, Docket No. R-4111, under which one source of exploration capital has been proscribed.

2. *Quality Standards.* The Commission erred in not adopting a proportionate upward adjustment for gas with a Btu content in excess of 1,000 Btu. Mobil adopts the "Shell Group's" Application for Rehearing on this issue.

3. *Adjustment of Applicable Area Rate for New or Additional Taxes or Assessments.* The Commission erred in failing to provide for future adjustments to applicable area rate levels for any new or additional taxes or assessments. In so doing, the Commission has departed from its Opinion No. 595-A, issued October 18, 1971 in the Texas Gulf Coast Area Rate Proceeding, Docket Nos. AR64-2, *et al.* By reason of such error, the Commission failed to protect the adequacy and the stability of the producer area ceiling rates for the future during the lengthy moratorium provided in Opinion No. 607.

4. *Contingent Additional Royalty Payments.* The Commission erred in failing to include in its current cost estimate

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and in its flowing gas-well gas cost estimate an allowance for additional royalty payments required under Opinion No. 562. In that Opinion, the Commission held that a producer must pay royalty under market value royalty clauses at the applicable just and reasonable rate regardless of notice and rate filing requirements and without regard to contract limitations. Such additional royalty expense reduces the producer's net working interest revenue and increases its revenue requirements accordingly. The Commission has failed to measure the impact of its Opinion No. 562 in this case and its effect on the capital requirements of this industry, especially during a lengthy moratorium.

5. *Rate of Return.* The Commission's rate of return allowance is sufficient to be commensurate with returns on investments of corresponding risks and uncertainties, inadequate to attract capital necessary to meet the Commission's projections and inadequate to assure the financial integrity of the producing industry, past and future. In addition, the finding fails to adequately compensate the gas exploration and producing industry in the light of rising costs, inflation, increased demands, intrastate competition and other relevant factors.

6. *Moratorium.* Any moratorium on the filing rate increases under Section 4 of the Act must be supported by pro-

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per findings resting upon substantial evidence and must be reasonable. See *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968); *Southern Louisiana Area Rate Cases, supra.* A moratorium in excess of one year in a period

of inflation, changing costs, rising demand, and inadequate supply, is not reasonable.

In this instance, the combination of low area rates, insufficient interim escalations, and a moratorium of over four years, also is not supported by substantial evidence or required findings. In its opinion, the Commission recognizes that a period of inflation and rising costs can be expected over the next few years. Yet, neither evidence nor findings support the minimal escalations to be allowed under a moratorium extending to July 1, 1976.

The Commission is requested to reconsider these related provisions of its order and to provide for a moratorium expiring no later than November 1, 1972.

7. *Refunds.* The Commission is well aware that the imposition of refunds produces negative incentive. Flowing gas rates should be adjusted to eliminate any substantial amounts. It is not clear from Opinion No. 607 what the amounts involved in refunds are. Regardless of the amounts the Commission is quite correct in its implicit recognition that a negative incentive cannot be made positive by erecting a *forgiveness* of refunds wrongly imposed in the first instance.

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Mobil urges the Commission to reconsider and set aside the provisions for "Refunds." In the absence of additional evidence and further findings, these provisions are not properly supported, and, on their face, have the unlawful effects cited which are inconsistent with the need for vital capital formation in the industry.

CONCLUSION

On the basis of the foregoing argument and authorities, Mobil requests that the Commission grant rehearing of its Opinion No. 607 and upon reconsideration thereof, modify such opinion so as to correct the errors specified herein, and in the Application for Rehearing by the major producer "Shell Group", to the extent not inconsistent herewith.

Respectfully submitted,

MOBIL OIL CORPORATION

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By /s/ ROSCOE C. ELMORE
ROSCOE C. ELMORE

November 24, 1971
Houston, Texas

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

APPLICATION FOR REHEARING OF THE SUPERIOR OIL COMPANY

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I. The Commission erred in ordering Paragraph (B) in fixing the base area rates established for the purpose of calculating refunds at a level too low to induce exploration.

II. The Commission erred in not providing a means in its order for the respondent producers to discharge their several refund obligations by dedication of additional gas reserves.

III. The Commission will err in failing to grant Superior a special exemption in that the operations conducted by Superior in this area are atypical of those of the group.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

APPLICATION FOR REHEARING OF THE SUPERIOR OIL COMPANY

Pursuant to the provisions of Section 19(a) of the Natural Gas Act,[1] THE SUPERIOR OIL COMPANY, hereinafter called "Superior", hereby petitions for rehearing of the Commission's conclusions and the orders resulting therefrom contained in its Opinion No. 607 dated October 29, 1971. In support hereof Superior shows as follows:

Superior is a party Respondent in this proceeding under Docket Nos. RI68-83, RI68-253, RI68-717, RI71-1135, G-20347, RI61-83, G-14106, The Superior Oil Company (Nevada) and James W. Harris, and G-18694, The Superior Oil Company and Gas Rock Corporation, some of which are consolidated and some of which are included in Part IV of Appendix A of the Opinion as Section 4(e) dockets not consolidated in AR67-1. Superior is aggrieved by the orders of the Commission contained in said Opinion No. 607 in that (a) the same require Superior to reduce its present rate for the sale of natural gas in certain of the above numbered dockets below a just and reasonable rate;

[1] Title 15 U.S.C. 717r(a)

(b) require Superior to refund with interest amounts collected pursuant to its several sales contracts to the extent such collections exceed the refund rates established in said Opinion No. 607 for certain time periods set forth thus depriving Superior of a just and reasonable rate for such gas; and (c) prescribes a moratorium on rate increases for a time certain thus precluding Superior from seeking any interim rate relief from the unreasonably low and the confiscatory gas rates fixed.

This application is filed within thirty (30) days following the issuance of said Opinion No. 607 and is based upon the hereinafter set forth specific errors in said Opinion No. 607 as to which rehearing is here sought.

Superior has only five (5) rate schedules in the (Other Southwest Area) nevertheless the impact of the Commission's orders on Superior as to refunds[2] is slightly greater than the impact on Superior of the Texas Gulf Coast decision.[3] Superior will not dwell on the Other Oklahoma rates[4] but will concentrate

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[2] By careful estimate without calculation in finite detail Superior (Other Southwest Area) refund obligation as the order now stands will amount to $3,120,870.00 inclusive of interest. By comparison the Gulf Coast Burden is $3,081,189.00, thus making inaccurate as to Superior the finding in paragraph 47 to the general effect that the small amount of refund credit could not provide an incentive for increased exploration and development in the area.

[3] Opinion Nos. 595 and 595-A.

[4] Which rates are also deficient, but will no doubt be severely excepted to by producers more vitally interested in that area than Superior which exceptions we adopt to the extent not inconsistent herewith.

its attention upon the errors it deems to have been made in fixing rates in Mississippi and Alabama for gas under contracts dated before October 1, 1968. The refund obligations created are under Superior's Rate Schedule No. 11 at Gwinville and Superior's Rate Schedule No. 15 at Baxterville and amount to $3,104,644.00 including interest, estimated as in fn. 2.

I.

Posing the problem in the terms in which the Commission considered it[5] the Commission erred in fixing flowing gas or refund calculation rates at too low a level in the presence of substantial evidence which would have permitted otherwise.

Producer witness Beebe[6] testified as to the excellent possibilities for production in Mississippi. True enough he also said[7] "risk is greater, and larger reserves must be anticipated to justify the costs and risks involved" but he forsees that the opportunity is there.

Superior concedes arguendo that both the upper guideline rate for initial service and the in-line price were slightly higher in Mississippi than the comparable amounts for Southern Louisiana, and that contract rates for Mississippi gas after 1961

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[5] Opn. No. 598 Capital formation has been declining Item 93, p. 40. Flowing gas represents an important source of capital Item 104 p. 44, we reject any "what-the-traffic-will-bear" approach Item 101, p. 43.

[6] Tr. 9/928-975 Exhibit 1, and particularly Tr. 9/960.

[7] Tr. 9/963.

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appeared to have been lower than in Southern Louisiana. Even so, as of December 31, 1962[8] the effective price[9] derived from rate schedules of producers filing the all areas questionnaire in the State of Mississippi exceeded the 19 cents[10] fixed by the Commission for the time period prior to January 1, 1965 for 91.06% of the volumes sold. These prices ranged from 19 cents[10] to a high of 23.40 cents.[10] As of January 31, 1966 (in the second vintage pricing period) 85.46% of the volumes sold were sold at effective prices ranging from 19.50 cents[10] to 24.99 cents.[10] [11]

Producer witness Rhoads Foster[12] in reliance on the foregoing existing structure of prices in Mississippi, *the relationship with prices in other sectors of the market, particularly Southern Louisiana*, Mr. Beebe's evidence on gas supply potential as well as

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the risk and hazard of deep drilling in Mississippi, supra, and the need to induce exploratory activity in Mississippi recommended a Mississippi flowing gas price or one for refunds calculation and a Mississippi new gas price both identical of 22.6 cents/Mcf at 15.025 psia.

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[8] Exhibit 51. J. Rhoads Foster p. 34.

[9] Defined at Tr. 20/2610 as being the price filed and made effective whether subject to refund or not.

[10] The tabulations referred to are at 14.65 psia whereas the Commissions 19 cents is at 15.025. At 15.025 the comparability is 19.5 cents to 24.0 cents and 20.0 cents to 25.63 cents.

[11] Exhibit 51. J. Rhoads Foster p. 35.

[12] Tr. 20/2620-22.

It may be that the prior Commission two price policy combined with common vintaging may make the Commission either reluctant or opposed to departure therefrom, but this need not detract from the weight of the Foster flowing gas price recommendation.

Superior takes the view that the greater volume of its Mississippi gas is delivered at or above the BTU maximum and that even if total deliveries in the entire state have a lesser BTU content the accessibility to the Eastern Seaboard market of Mississippi gas creates a commodity value to the pipeline purchaser equal to or greater than that of South Louisiana gas of the same vintage.[13]

Accepting arguendo the vintaging dates as policy established in prior decisions, Superior shows that the Commission's own comparison with the Southern Louisiana area rates establishes the inadequacy of the Mississippi Alabama rates here fixed.[14] Resort to the comparable Southern Louisiana vintage prices for the purpose of calculating Mississippi refunds (the flowing gas prices)

for the two escalation periods the Commission created discloses the inadequacy. Following such comparison, the base area rates for Mississippi and Alabama old gas, and for calculating refunds, would become (1) 19.70 cents per Mcf for deliveries prior to January 1, 1965; (2) 20.30 cents after that date to September 30, 1968;

[13] Any BTU penalty implicit in the swing from 950 to 990 BTU as compared with 1000 to 1050 BTU Southern Louisiana gas is more than offset by location value.

[14] Opn. 607, p. 21. The 22.375 cent rate fixed in Southern Louisiana for post 8/1/71 deliveries adjusted for tax differences only equated to 21.37 cents for Mississippi and Alabama.

and (3) 21.37 cents for the period of time commencing October 1, 1968.[15]

In the above connection the Commission here should take official notice of its own actions in other proceedings taken for the purpose of alleviating the existing shortage of domestic natural gas. It has authorized importations of liquified natural gas from foreign countries at prices of $1.14 per Mcf, $1.37 per Mcf, $1.52 and $1.66 per Mcf for Algerian gas at ship side,[16] and approximately $2.20 per Mcf for Canadian gas delivered to the system of Boston Gas Company,[17] and has granted temporary authorization for a ship load of Algerian LNG to cost .68 cents per Mcf

[12,305]

ship side and will be delivered from the terminal near the point of loading at $1.04 per Mcf.[18] Where there has been a hearing, it has been argued that such imports are needed and there is no cheaper available alternative. Even now the Commission has before it applications for long term importations which if permitted will enable

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[15] The comparable Southern Louisiana prices for the periods stated were (1) 20.625 cents; (2) 21.25 cents; (3) 22.375 cents. These prices are for gathered gas. Where gathering is done by the purchaser (as is Superior's situation in its largest Mississippi sale) in Southern Louisiana, a deduction of .51 cents per Mcf was required. It is significant that that amount was one agreed to by most producers, most distributors, all pipelines and the Commission Staff. In Mississippi and Alabama the deduction for gathering has been fixed at 1.25 cents which seems unreasonably high.

[16] Boston Gas Company, Docket No. CP69-112.
Texas Eastern Transmission Corp., Docket No. CP70-208.
Lowell Gas Company, Docket No. CP70-143.
Boston Gas Company, Docket No. CP71-248.

[17] Willbros Terminal Company, Docket No. CP70-194.

[18] Distrigas Corp., Docket No. CP70-196.

the pipeline companies involved to obtain gas into their systems at estimated costs of 80.4 cents per MMBtu to Southern Natural Gas Company compared with its otherwise cost of service based on domestic purchases of 47.2 cents per MMBtu.[19] In the same proceeding Consolidated System LNG Company proposes to purchase LNG at a price of 97.5 cents per Mcf (delivered at Leidy) while its present supply is available at 53.26 cents per Mcf.[20] Thus these two companies would pay on a cost of service basis 33.2 cents per MMBtu and 44.24 cents per Mcf more for imported LNG than they have been paying on the same basis for domestic gas.

Mississippi and Alabama could provide a cheaper alternative for the needed supply of gas if the funds for exploration and development were available to find and produce it. The evidence in this record is clear that the gas is believed to be there if it can be found and produced.[21] Staff witness Engle has testified,

[12,306]

Exhibits 109, 110, 111 in Columbia LNG Corporation, et al., Docket No. CP71-68, that Southern Natural Gas Company, one of the largest pipeline purchasers in Mississippi, could buy gas at 26 cents per Mcf offshore Southern Louisiana and have a total in-system-cost of only 47.07 cents per Mcf. Recognizing again the shorter haul from Mississippi on or offshore, this rate would be reduced by several cents for Mississippi gas.

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[19] Southern Energy Company, et al., Docket CP71-68.

[20] Exhibit P, Amended Schedule, No. 2, page 2. Consolidated System LNG Co., Docket No. CP71-290. Exhibit N, Schedule 1, Part 1 Amended.

[21] See fn. 6, supra, witness Beebe.

The capital for necessary exploration comes from the revenues produced by gas now being sold and of course must be induced to a particular use by an incentive for investment in the project. To fix Mississippi and Alabama prices for flowing gas at a level that does not provide through both past sales and refund savings, and present sales, the necessary capital to bring about increased exploration in that area is contrary to the general public interest and will not provide gas consumers with gas at the lowest reasonable price. The prices for flowing gas in this area have, under Commission guidelines, been higher than those in Southern Louisiana and now should be fixed no lower than prices for that area.

II.

Superior does not know the total possible refund amounts of other producers in the Other Southwest Area. As pointed out in I above, flowing gas prices should be so fixed that refunds, if any, would be quite small; nevertheless, if refunds are required at all, they should be permitted to be used for exploration, and dedication of additional reserves, and the Commission erred in not providing a means in its order for the Respondents to do so.

Superior believes this to be in the public interest no less than it is in Superior's interest. There is no doubt that newly discovered domestic natural gas continues to be the best solution to the natural gas supply problem. The Commission has doubtless already taken official notice of the finding of its own Bureau of Natural Gas that the magnitude of the shortage is 21% of demand by 1975 and 30% of demand by 1985 after full allowance for supplemental supplies which it was noted range from

75 cents to $1.00 per Mcf for imported LNG and Alaskan North Slope gas, from 75 cents to $1.25 per Mcf for synthetic gas manufactured from coal, and from $1.10 to $1.40 Mcf for synthetic gas manufactured from naptha and LPG.

III.

Alternatively to the above, if the prices for flowing gas in Mississippi and Alabama are not fixed at rates equal to those to be paid to the producers in the Southern Louisiana area, Superior should be entitled to a special exemption from said order for the following reasons:

1) If the overall refunds in this area are so small that their application to exploration and development costs would not be a producer incentive, then Superior is atypical to the area producer group. Its refund obligation under the complained of order would exceed three million dollars. This is a very significant amount for Superior and its retention will be an incentive to exlore for added reserves.
2) A very large portion of Superior's potential refund total accrued before the concept of area rate fixing, and the use of industry average costs became established as a valid rate fixing method.
3) Should individual producer cost of service be considered the applicable method of determining the just and reasonable rates for time periods prior to establishment of area rate fixing, then Superior's

cost of service would justify all of the amounts Superior has collected in this area.[22]

[22] Witness Pat F. Timmons, Tr. 1262, Exhibits Nos. 21 and 22.

Superior therefore respectfully requests in the alternative that its rates be fixed at those collected by it in this area unless the rates fixed for the Mississippi-Alabama sub-area are established so as to net to the producer unit revenues equal to those fixed by this Commission in the Southern Louisiana Area.

CONCLUSION

WHEREFORE, THE SUPERIOR OIL COMPANY PRAYS THAT the Commission rehear this matter and reconsider its Opinion No. 607 correcting the errors above pointed out, including, if not otherwise rendered unnecessary, a special exemption for Superior on the basis of its showing herein, or subject to such further showing as may be reasonable in the premises.

Respectfully,

THE SUPERIOR OIL COMPANY

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November 24, 1971

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL POWER COMMISSION

Docket Nos. AR 67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
OTHER SOUTHWEST AREA

PETITION FOR REHEARING OF THE NEW YORK STATE PUBLIC SERVICE COMMISSION

Pursuant to Section 19(a) of the Natural Gas Act and Section 1.34 of the Rules of Practice and Procedure of the Federal Power Commission (Commission), the New York State Public Service Commission, an intervenor herein, applies for rehearing, by petition under oath, of the Commission's Opinion and Order Determining Just and Reasonable Rates for Natural Gas Produced in the Other Southwest Area (Opinion 607), issued in the above entitled proceeding on October 29, 1971.

SPECIFICATION OF ERRORS

Before detailing the errors in Opinion 607, we note that we do not object to the Commission's ultimate conclusion that the just and reasonable area price for *future* vintages of gas well gas, subject

[12,317]

to various state taxes and pressure bases should be 22.5 —25 cents per Mcf. As we discuss below, we challenge any retrospective application of this price and its application to oil-well gas. We also challenge the 26 cents

price per Mcf established for that part of offshore Mississippi located in the federal domain. We also wish to make it clear that in accepting the prices established for future vintages in the Other Southwest Area, we do not subscribe to the Commission's hodge-podge, undefined zone of reasonableness approach which the Commission apparently has adopted here. Furthermore, since the Commission apparently relies in large measure here on Opinion 595 (Texas Gulf Coast) and Opinion 598 (Southern Louisiana II), with respect to new gas costing, automatic price escalations, and industry capital requirements we respectfully incorporate herein, in their entirety, our petitions for rehearing from those Opinions.

1. Although we do not object to the new gas-well gas price of 22.5—25 cents per Mcf, we deem it desirable to note the following substantial errors in the Commission's apparent selection of an overall rate of return. This is by no means a hypothetical objection since the same, astronomical return is used to support some of the flowing gas prices, to which we make specific objection below.

The Commission reliance on a rate of return of approximately 15 percent (mimeo, p. 13 n. 15) is completely unsupported by findings,

and indeed such findings could not be made since the record does not contain evidence that would support such findings. Moreover, the Commission has failed to state the time period to which this return is to be applicable and has failed to make any findings as to the return on equity which producers would receive from an overall

return of 15 percent.[1] The Commission has elsewhere determined that producers generally have at least a 15 percent debt ratio (34 FPC at 201). Assuming that embedded debt costs are 6 percent, the overall 15 percent rate of return affords 16.6 percent on producer equity. The Commission's judgment to this effect must be explained but it has not been explained. To the extent the extraordinary return could be justified on grounds of incentive (though the Commission has not done so here), that would apply only to future vintages and cannot be rationalized for all the vintages to which the Commission is applying its rate of return conclusion.

[12,319]

2. The Commission erroneously allowed automatic escalations of the area ceilings for new gas (mimeo p. 18). Neither projected cost increases nor projected decreases in productivity trends warrant increases in price over the life of a vintage of gas. If and when cost increases are incurred which push costs for a successive vintage above the ceiling established for new gas, a new ceiling for that vintage should be established. If, for example, the cost of finding gas increases to 27 cents in 1978, then the price ceiling for gas dedicated in 1978 may be set at 27 cents. That does not justify raising the ceiling for 1973 gas from 25 cents to 26 cents. General inflation

[1] A 15 percent overall rate of return is particularly excessive when viewed in light of the returns found reasonable in Opinions 468 and 546. In *Permian*, the Commission's allowance of a 12 percent return expressly included an increment to reflect the risk of finding gas of less than pipeline quality. This meant, as the Commission stated in court, that a return allowance of no more than 10½ percent was deemed appropriate for new gas-well gas and about 9 percent for flowing gas. In *Southern Louisiana*, a return of 12 percent was also allowed, but again based on the special circumstances in the area.

does not justify provisions for future escalations since the rate selected here by the Commission, which is based on the upper range of the various individual cost elements, already compensates producers for any inflationary pressures. In addition this automatic escalation provision appears to be antithetical to the purposes of the Economic Stabilization Act of 1970 and other federal policies to combat inflation. When and to the extent the unit cost of dedicated new gas rise above 22-25 cents, the Commission may later allow measured escalation.

3. The Commission's selection of October 1, 1968 as the beginning date for pricing new gas was in error. The

[12,320]

Commission's reason for this action, *i.e.*, "to avoid multiplicity of division dates" (mimeo, p. 14) does not justify this action.

In *Permian*, the Supreme Court reluctantly approved establishing a price for new gas in 1965 applicable to gas committed to interstate commerce since January 1, 1961. Although stating (390 U.S. at 798-99),

> "[I]t is difficult to see how the higher rate could reasonably have been expected to encourage, retrospectively, exploration and production that had already occurred,"

the Court noted the Commission's belief that its September 1960 statement of General Policy created expectations of higher rates among producers which must be satisfied. This, the Court held provided a permissible basis for the Commission's action. The Commission's action here does not rest on such a basis. The Commission's choice of October, 1968 negates the whole concept of vintaging and is an unduly high price to pay for any

possible administrative convenience while providing a windfall to the producers.

4. The Commission erroneously established the same area rate for gas produced in the Federal domain offshore Mississippi as that for the Federal domain offshore Louisiana. As we noted in our petition for rehearing in *Southern Louisiana II*, offshore gas in

[12,321]

the Federal domain is not subject to state production taxes and there is nothing in the record, either here or in *Southern Louisiana II*, to indicate that the unit cost of offshore drilling relative to the gas found is considerably higher than onshore for gas of the same vintage. Furthermore, the Commission's discussion leaves a gap in that there is no discussion of the appropriate pricing level for land-based gas on federal enclaves such as Wheeler Air Force Base.

5. While we do not challenge the initial ceiling prices for middle vintage gas (1961-October 1, 1968 gas-well gas, subject to State Tax), as established in the initial decision, there is no basis, for either the past or future escalations permitted for this gas. The escalations are especially objectionable because the price ceilings already reflect generous allowances for the producers. The discussion in paragraph 2 is also applicable here. Moreover, this ceiling should be applied to gas dedicated to interstate commerce on or before the date of the Commission's Opinion here; that is, for the period October 1, 1968 to the Commission's Order, the middle vintage ceiling should apply, not the new gas price.

6. The Commission erroneously established a 15 cent rate for flowing gas under contracts dated before January 1, 1961 in Texas District 6 and a 16.7 cents per

Mcf rate in Northern Louisiana. The Commission allegedly established these rates for the reasons

[12,322]

stated in *Texas Gulf Coast.* As we stated in our petition for rehearing there (p. 8):

> "The Commission here accepted the Examiner's determination that the cost of flowing gas under contracts dated January 1, 1961 was 13.68 cents per Mcf. The Commission has, however, increased this figure to 15.0 cents per Mfc so that producers would not receive less than their costs (mimeo p. 38). The Commission does not explain how this margin of 1.3 cents was determined except to state that this will assure that the producers will not receive less than their costs. But the Commission's primary function is to protect the consumer against excessive charges. While costing is not a science, there is no reason to assume that the Examiner's costs are too low rather than too high."

Those objections also apply here.

The Commission's sanction to automatic escalations in flowing gas prices in all sub-areas is without record or adequate findings.

As a prime reason for escalating this price the Commission cites well drilling cost increases. However, to the extent these are successful drilling costs in more recent years they do not increase the cost of flowing gas (for which drilling was completed long ago).

[12,323]

Although such cost increases may affect the E&D allowance, the Commission has not attempted to measure

the impact of such increases, and their relation to offsetting cost decreases such as the declining net investment for older gas, but rather has arbitrarily established a price escalation which is unjustified and should be eliminated.

7. The Commission erred in setting the same area rates for casinghead gas as for gas-well gas. In Opinions 468, 546, and 546-A the Commission consistently held that casinghead gas should not receive the higher prices allowed more recent vintages. 34 FPC 159, 209; 40 FPC 530, 590; 41 FPC 301, 315. In Opinions 546-A the Commission stated that (41 FPC at 315):

> ". . . [W]e can perceive no justification for continuing to allow the more recent vintages of this gas to command a price which is based in part on an additional allowance which includes an incentive for increased exploration and development and which is predicated on the industry's directional exploration capability. Moreover, while we have consciously refrained from attempting to define the cost of casinghead gas, we are well aware that is indicated cost is substantially below that of gas-well gas."

[12,324]

The Commission apparently recognizes that casinghead gas is less costly to produce than gas-well gas, but attempted to justify its decision in *Texas Gulf Coast* and *Southern Louisiana II*, on the basis that price equality will prevent diversion to the intrastate market. There is no point, however, in allowing a higher price for this gas in an attempt to prevent its diversion to the intrastate market. First, with regard to casinghead gas from the Federal domain offshore, that gas is by definition in the interstate market and is subject to FPC regula-

tion. Second, with respect to onshore casinghead prod
tion, there is nothing to indicate that the intrastate m
ket will not always be able to outbid the interstate m
ket for any category of new gas whatever ceiling is fi
by the FPC, it is pointless for the FPC to inflate
price for casinghead gas in an effort to keep it out
the intrastate market.

8. The Commission erred if it reasserted the spec
exemption established in Order No. 428 for small p
ducers making jurisdictional sales here (mimeo p. 7
Under the Commission's decision in Order No. 428, sm
producers everywhere would be relieved of all obligati
under Sections 4, 5 and 7 of the Natural Gas Act. Th
we have maintained is without legal justification. The
fore, grant of such treatment here is without

[12,325]

justification. Furthermore, the Commission compou
the error if it makes the exemption retroactive, free
small producers of any refund obligation arising fr
excessively priced past sales.

9. The Fifth Circuit in *Austral Oil Co.* v. *FPC*,
F2d 407 (CA5, 1970), established rigorous standa
calling upon the Commission to discuss in detail the sup
to be elicited at the rates established (428 F2d at 44
The Commission here has sought to discharge its
sponsibility by a few conclusory statements to the ef
that it does not know what supply will be elicited at
price (mimeo pp. 11-12). The Commission's discus
is totally inadequate, failing to explain how it arri
at its conclusion. Sympathetic though we are to
difficult responsibilities placed upon the Commission
the Fifth Circuit's decision, the Commission cannot a
an effort to discharge those responsibilities. Furth

more, the Commission commended the Fifth Circuit decision in its response to the Supreme Court opposing the grant of writs of certiorari. Of course, definite, precise figures could not be given, but estimates giving the Commission's best judgment of what it believes will be the supply result of its rate orders must be given and explained.

[12,326]

10. While we have already incorporated by reference our objections to the Commission's determination to the capital requirements of the industry (mimeo p. 12), we deem it desirable to restate our position. The Court in *Austral* criticized the Commission's Opinion No. 546 for making only conclusionary findings as to the availability of capital to satisfy demand (428 F2d at 436-37 & n. 93) and for estimating the total expected revenue from those rates "in a vacuum." (428 F2d at 437 & n. 94). In its recommendations, the Court stated that the Commission must make more specific assessments on the capital actually available to the industry as a whole. (428 F2d at 441). Here, the Commission has apparently erroneously adopted the testimony of UDC Witness Winger in *Southern Louisiana II*. As we stated in our petition for rehearing there, this testimony is questionable at best and should not be relied upon (pp. 23-24). In that proceeding as here the Commission fails to come to grips with the problem of how much of the additional funds necessary for investment by the oil and gas industry should be generated by internal means, bearing in mind the fact that natural gas sales amount to less than 5% of total industry gross revenues. Rather, it has only made highly generalized statements, justifying no particular portion of the various rates it has approved. Contrary to the

[12,327]

Commission apparent belief that there is a need for internal gas generation of funds for the gas search, the industry has found sufficient capital to invest heavily in the North Sea, Northern Slope, and Offshore Louisiana area, for example, based on general sources of funds.

CONCLUSION

For the foregoing reasons, the New York State Public Service Commission seeks a rehearing on the merits of Opinion 607 and for such other relief as the Commission may allow.

Respectfully submitted,

/s/ Joseph J. Klovekorn
JOSEPH J. KLOVEKORN
Staff Counsel

Date: Albany, New York
November 26, 1971

Order Granting Rehearing

[12,330]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: John N. Nassikas, Chairman; John A. Carver, Jr., Albert B. Brooke, Jr., Pinkney Walker, and Rush Moody, Jr.

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

ORDER GRANTING REHEARING FOR PURPOSE OF RECONSIDERATION

(Issued December 23, 1971)

Applications for rehearing of Opinion No. 607 and its accompanying order, issued October 29, 1971, were filed on November 26, 1971, by the State of Texas, Shell Oil Company, *et al.*, The Superior Oil Company, Amoco Production Company, and Mobil Oil Corporation, and on November 29, 1971, by the New York State Public Service Commission.

The Commission finds:

It is appropriate and in the public interest to grant rehearing on the aforesaid Opinion and order for the purpose of further consideration as hereinafter provided.

[12,330]

Order Granting Rehearing

The Commission orders:

Rehearing on Opinion No. 607 and its accompanying order issued October 29, 1971, is hereby granted for the purpose of further consideration.

By the Commission.

[SEAL]

KENNETH F. PLUMB,
Secretary.

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UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

OPINION NO. 607-A

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*

(OTHER SOUTHWEST AREA)

ORDER ON REHEARING

Issued: January 17, 1972

[12,332]

UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: John N. Nassikas, Chairman; John A. Carver, Jr., Albert B. Brooke, Jr., and Pinkney Walker.

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

ORDER ON REHEARING

Opinion No. 607-A

(Issued January 17, 1972)

1. Timely applications for rehearing, reconsideration and clarification of Opinion No. 607 and its accompanying order, issued October 29, 1971, were filed by Shell Oil Company, *et. al.* (a group of major independent producers, hereafter referred to as Major Producers), Mobil Oil Corporation (Mobil),[1] The Superior Oil Company (Superior), the State of Texas,[1] and the New York State Public Service Commission (NYPSC), and by Amoco Production Company (Amoco) as a supplement to the Major Producers' application in which Amoco joined. By order issued December 23, 1971, the Commission granted rehearing solely for the purpose of further consideration.

[1] Mobil and Texas adopted the Major Producers' exceptions, Mobil making an additional presentation.

REQUESTS FOR CLARIFICATION

2. The Major Producers request it be made clear that casinghead gas, as well as other gas, produced on or after

November 1, 1969, from new reservoirs on committed acreage is vintaged as of the date of discovery, rather than the date of the contract first committing it to interstate commerce. Our order will make this clear.

3. The Major Producers further request that it be made clear that refund rates will not be required below a settlement rate approved by final order of the Commission. There is no question but that a finally approved settlement is determinative as to all matters covered by it. So there can be no misunderstanding, this order will be explicit upon that point.

REQUESTS FOR MODIFICATION

4. The Major Producers and Superior urge that producers should be permitted to discharge any refund obligation by dedication of additional gas reserves in the same manner as provided in our recent decisions with respect to Southern Louisiana (Opinion Nos. 598 and 598-A, —— FPC —— (1971)), and Texas Gulf Coast (Opinion Nos. 595 and 595-A, —— FPC —— (1971)). Upon reconsideration, we agree. While the estimated amount of $5,000,000 (the Major Producers' estimate) is small by comparison with total dollar revenues of the industry in this area, and although the resulting stimulus may not be great, in this time of increasing gas supply stringency every incentive should be applied which may help to alleviate the situation.

5. The Major Producers request modification of the quality standards to provide for (a) upward and downward adjustments in rates on the basis of a 1000 Btu per cubic foot standard (except in Mississippi and Alabama), (b) use of the particular contract provisions to establish quality standards for gas under contract before the effective date of this order and (c) no downward adjustment in rate if the pressure is high enough to allow the gas to enter the pipeline. While we find

no merit in the first two requests for modification of the quality standards, the third should be granted. See *Texas Gulf Coast Area Rate Proceeding*, Opinion No. 595-A, —— FPC —— (1971).

6. The Major Producers and Mobil urge that rates should be increased in the event of tax increases. We agree and will so order. See *Texas Gulf, supra.*

7. The Major Producers ask that our prior order be modified to allow rate changed attributable to changes in Btu content to be computed and collected without additional rate change filings with this Commission. This has been the practice in other areas and should be approved.

8. The Major Producers request an extension of time to file refund reports from February 1 to April 1, 1972. This request is granted.

9. Except for the foregoing, the application for rehearing, or for special exemption, and motions which would affect the result in Opinion No. 607 and its accompanying order have presented no arguments not previously considered by the Commission which would affect our determination here, and their requests are denied.

Order on Rehearing

The Commission finds:

(1) The arguments, assignments of error and grounds for rehearing set forth in the applications for rehearing or for special exemption or motions which would affect the result in Opinion No. 607 and its accompanying order present no facts or legal principles which would warrant any change in or modification of the Commission's Opinion No. 607 and its accompanying order except as specified below.

(2) In view of all the facts and circumstances in this case, the Commission's action herein is consistent

with the Economic Stabilization Act of 1970, as amended, and regulations existing thereunder.

The Commission, acting pursuant to Sections 4, 5 and 16 of the Natural Gas Act (52 Stat. 822, as amended 823, 830, 15 U.S.C. 717c, 717d, 717o) and Sections 553, 556 and 557 of Title 5 of the United States Code (the Administrative Procedure Act, 60 Stat. 238, 239, 241, 242, as codified September 6, 1966, by 80 Stat. 383, 384, 386, 387) orders:

(A) Part 154 of the Commission's Regulations under the Natural Gas Act, Subchapter E, Chapter I, Title 18 of the Code of Federal Regulations (18 CFR 154) is amended by adding a new subparagraph (4) at the end of paragraph (c) of Section 154.109a, which new subparagraph reads as follows:

Section 154.109a ***

(c) ***

(4) Notwithstanding the provisions of subparagraphs (1), (2) and (3) of this paragraph, the

base area rates for gas produced on or after November 1, 1969, from a new reservoir on previously committed acreage shall be determined by utilizing the date of discovery of such reservoir in lieu of the contract date.

(B) Ordering paragraph (B) of Opinion No. 607 amended by the addition of a new subparagraph (5), which subparagraph reads as follows:

(5) Notwithstanding the provisions of subparagraphs (1), (2) and (3) of this paragraph, the base area rates for gas produced on or after November 1, 1969, from a new reservoir on previously committed acreage shall be determined by utilizing the date of discovery of such reservoir in lieu of the contract date.

(C) The date of discovery of new reservoirs, whether

the gas be casinghead or gas-well gas, shall be established in the manner provided in Section 2.56(f)(2) of the Commission's Rules of Practice and Procedure.

(D) Ordering paragraph (C) of Opinion No. 607 is amended by addition of the following: "or the rate established by a settlement approved by final order of the Commission still in full force and effect and governing the actions of all parties thereto."

(E) *Discharge of Refund Obligations by Additional Dedications.* Each producer who so elects may discharge its refund obligation in this proceeding through credits for dedication to sale to interstate pipelines, after the date of issuance of this order and prior to January 1, 1976, of gas reserves in the Other Southwest area in addition to those already dedicated to interstate com-

merce on the effective date of this order. New reservoirs discovered after the date of issuance of this order on acreage committed by a contract for sale to an interstate pipeline shall be considered to be new dedications for the purpose of this paragraph. The amount of the credit shall be one cent for each Mcf so dedicated, provided that, except in case of a *bona fide* and rejected offer of new dedications as hereinafter set forth, not more than fifty percent of the refund obligation owed any one buyer may be discharged by new dedications to another buyer or buyers in amounts greater than necessary to discharge seller's existing refund obligation, if any, to such other buyer. New dedications, to the extent greater than necessary to discharge an existing refund obligation to the buyer, shall be used to reduce the producer's remaining refund obligations to all other buyers as to each in proportion that the obligation owed to each bears to the remaining total refund obligation of such producer, except that, if a buyer to whom a refund is owing by a producer rejects a *bona fide* written offer of new dedications from the producer, the producer may, if it dedicates the offered reserves to sale to another interstate pipeline, credit

[12,337]

against its obligation to the prospective buyer which first rejected the offer any unused credit over and above that which can be used to reduce the producer's refund obligation to the actual buyer. In no event shall the producer's total refund obligations be reduced by more than one cent per Mcf of new dedications. If a producer's refund obligation has not been completely discharged by January 1, 1976, such producer shall be obligated to refund in cash plus 7 percent interest from the date of

refund report, the outstanding refund obligation (including interest to the date of refund report).

(F) The first sentence of ordering paragraph (G) of the order accompanying Opinion 607 shall be amended to read as follows: "Each respondent, who does not elect to discharge its refund obligation (including interest) in the manner set forth in ordering paragraph (E) of the order accompanying Opinion No. 607-A, shall retain the amounts shown in the report required under ordering paragraph (E) hereof subject to further order of the Commission directing the disposition of those amounts."

(G) Section 154.109(a)(2)(vi) of the Commission's Regulations under the Natural Gas Act, as established in ordering paragraph (A) of the order accompanying Opinion No. 607 is amended to read as follows:

> (vi) Delivery Pressure—The gas shall be delivered at a pressure sufficient to enter the buyer's pipeline, except that when the natural flowing pressure of seller's wells declines to, or below, the level sufficient for such delivery nothing herein shall require seller to deliver gas at a pressure higher than specified by contract.

(H) Section 154.109a(c) of the Commission's Regulations under the Natural Gas Act, as established

in ordering paragraph (A) of the order accompanying Opinion No. 607, is amended by adding a new sub-paragraph (4) which reads: "(4) The applicable area rate shall be adjusted upward or downward to reflect, from time of the change, 87.5 percent of any change in state or federal production, severance, gathering or similar taxes effective on or after October 29, 1971."

(I) Ordering paragraph B sub-paragraph (4), of the order accompanying Opinion No. 607 is amended by adding "and to upward or downward adjustment to reflect, from the time of the change, 87.5 percent of any change in state or federal production, severance, gathering or similar taxes effective on or after October 29, 1971."

(J) Where changes in the Btu content of particular gas occur after the filing of a rate applicable to that gas pursuant to the orders now and previously issued in this proceeding, any Btu adjustment to the applicable rate made pursuant to the terms of said orders may be computed and collected without further rate change filings, provided, that their currently proper Btu content rate adjustment shall be reflected in any later rate filing made with the Commission.

(K) The time for filing all refund reports and quality statements required in this proceeding is extended to April 1, 1972.

(L) Except as heretofore provided, all requests in the applications for rehearing, or for special exemption or motions which would affect the result in Opinion No. 607 and its accompanying order are denied.

(M) This opinion and order is subject to our Statement of Policy Implementing the Economic Stabilization Act of 1970 (P. L. 91-379, 84 Stat. 799, as amended by P. L. 92-15, 85 Stat. 38), and Executive Order No. 11615, including such amendments as the Commission may require.

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(N) This order shall constitute the certification of consistency with the purposes of the Economic Stabilization Act of 1970, as amended, as required by Section

300.016(b) of Chapter III, Title 6 of the Code of Federal Regulations.

(O) The Secretary shall cause prompt publication of the findings and ordering paragraphs, together with notice of the availability of this entire Opinion, to be made in the Federal Register.

By the Commission. Commissioner Moody not participating.

[SEAL]

KENNETH F. PLUMB,
Secretary.

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UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

APPLICATION OF MOBIL OIL CORPORATION FOR REHEARING AND RECONSIDERATION

COMES NOW Mobil Oil Corporation (Mobil), an aggrieved party to these proceedings, pursuant to Section 19(a) of the Natural Gas Act, 52 Stat. 832, 15 U.S.C. § 717(r) (Act), and Section 1.34 of the Federal Power Commission's Rules of Practice and Procedure, and hereby respectively applies for rehearing upon and reconsideration of the Commission's Order and Opinion No. 607-A issued January 17, 1972 in the above-entitled proceeding, upon the grounds hereinafter stated.

PRELIMINARY STATEMENT

Mobil filed a timely application for rehearing of Commission Opinion No. 607 and accompanying order issued October 29, 1971. The application for rehearing was denied by Commission Opinion No. 607-A and accompanying order issued January 17, 1972. Ordinarily, Mobil would not file another application for rehearing addressed to the supplemental opinion and order, even if the original opinion and order were modified in some respects, because a second application for rehearing would not be considered necessary for court review of the

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original and supplemental opinions and orders. In the present case, however, the Commission by its Opinion No. 607-A and order issued January 17, 1972, has radically revised and altered its original opinion and order with respect to its adoption of the controversial, anti-competitive and unlawful "refund credit" and related refund provisions from recent Commission decisions with respect to Southern Louisiana (Opinion Nos. 598 and 598-A, —— FPC —— (1971)), and Texas Gulf Coast Area Rate Proceedings (Opinion Nos. 595 and 595-A, —— FPC —— (1971)). As a consequence, the question has arisen whether this revision may be challenged on review without objection thereto having first been presented to the Commission in an application for rehearing. Out of an abundance of caution, to preserve its right to court review of such revision, Mobil files this application for rehearing.

The Commission may deem this application for rehearing unnecessary and accordingly reject it, or may accept and act on it. Whatever course the Commission follows, Mobil's right to raise in the court the challenge to Opinion No. 607-A and accompanying order hereinafter set forth will have been preserved. Should the Commission accept for filing this present application for rehearing, Mobil requests the

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Commission to act expeditiously on it to permit a petition for review to be filed no later than March 17, 1972, sixty days after January 17, 1972, the date of issuance of Opinion No. 607-A and order.

SPECIFICATIONS OF ERROR

Without waiver of the specifications of error included in Mobil's application for rehearing which was denied by Opinion No. 607-A and order issued January 17, 1972, and expressly continuing to rely thereon, Mobil applies for rehearing of Opinion No. 607 and accompanying order issued October 29, 1971, as modified and revised by Opinion No. 607-A and order issued January 17, 1972, on the following grounds:

1. The Commission erred in amending Ordering Paragraphs (F) and (G) of the order accompanying Opinion No. 607 by adding a new Paragraph (E) in Opinion No. 607-A, providing for the discharge of refund obligations by additional reserve dedications, in that such "refund credit" provisions, arrangement and system are anti-competitive in effect and operations, unjust, unreasonable, unduly discriminatory, unduly preferential, arbitrary, otherwise violative of the standards of Sections 4 and 5 of the Act, and unlawful.

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2. The Commission erred in adopting a rate design and refund-forgiveness program unsupported by required findings of fact, unsupported by substantial evidence, and without required opportunity to be heard thereon, and thereby has denied Mobil due process of law.

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Application for Rehearing of Mobil Oil Corporation

WHEREFORE, Mobil applies for rehearing upon and reconsideration of Opinion No. 607-A and order issued January 17, 1972, and urges the Commission to correct the error specified herein.

Respectfully submitted,

MOBIL OIL CORPORATION

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February 7, 1972

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UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

PETITION FOR REHEARING

The Public Service Commission for the State of New York (New York) herewith petitions for rehearing of Order No. 607-A, issued in this proceeding on January 17, 1972.

While Opinion No. 607-A is itself an order on rehearing, it amended Order No. 607, *inter alia*, to provide for the discharge of producer refund obligations otherwise ordered by Opinion No. 607 on a basis of one cent credit for each mcf of new gas dedicated to interstate commerce in the other southwest area. Since this provision was not a part of Order No. 607, we have not previously sought rehearing thereof. New York believes that there is even less justification on the record in this proceeding for this provision for discharge of refunds than there was in the Southern Louisiana and Texas Gulf Coast Area Rate proceedings. Even assuming it was otherwise appropriate to allow producers a rate for flowing gas higher than that the Commission has found just and reasonable for such gas, in addition to the just and reasonable price for new gas, there has been no showing that the

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alleged benefit to the interstate consumer, which the Commission recognizes "may not be great" in this area, approximates the $5,000,000 in additional revenues they would be required to pay.

Accordingly, the Public Service Commission for the State of New York requests the Commission on rehearing to strike the provisions of ordering paragraph (E) of Opinion No. 607-A.

Respectfully submitted,

PUBLIC SERVICE COMMISSION FOR THE STATE OF NEW YORK

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Errata Notice

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UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

ERRATA NOTICE

(March 3, 1972)

OPINION NO. 607-A
ORDER ON REHEARING

(Issued January 17, 1972)

Page 3, paragraph 7, line 2, change "changed" to "changes".

Page 4, paragraph (A), line 4, change "(4)" to "(5)".

Page 4, paragraph (A), line 8, change "(4)" to "(5)".

Page 4, paragraph (B), line 1, insert "is" after "Opinion No. 607".

Page 6, paragraph (G), line 1, change "Section 154.109 (a) (2) (vi)" to read "Section 154.09a (d) (2) (vi)".

KENNETH F. PLUMB,
Secretary.

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Order Denying Rehearing

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UNITED STATES OF AMERICA
FEDERAL POWER COMMISSION

Before Commissioners: John N. Nassikas, Chairman; John A. Carver, Jr., Albert B. Brooke, Jr., and Pinkney Walker.

Docket Nos. AR67-1, *et al.*

AREA RATE PROCEEDING, *et al.*
(OTHER SOUTHWEST AREA)

ORDER DENYING REHEARING

(Issued March 8, 1972)

On January 17, 1972, the Commission issued Opinion No. 607-A and its accompanying order, modifying and clarifying Opinion No. 607 and its accompanying order in this proceeding. Among other things, Opinion No. 607-A and its accompanying order for the first time in this proceeding provided that the refund obligations established in this proceeding may be discharged by the dedication of additional gas to interstate commerce by the particular producers owing refunds. On February 8, 1972, an application for rehearing and reconsideration with respect to this new matter was filed by Mobil Oil Corporation (Mobil), and on February 11, 1972, the Public Service Commission of the State of New York (PSCNY) filed a petition for rehearing on this new matter.

The provisions as to which rehearing and reconsideration are sought to allow a credit of one cent toward dis-

charge of any producer's refund obligations in the Other Southwest Area for each Mcf of new gas reserves dedicated by that producer to interstate commerce in the area from January 17, 1972, to January 1, 1976. Mobil characterizes these provisions (Application, page 3) as "anti-competitive in effect and operations, unjust, unreasonable, unduly discriminatory, unduly preferential, arbitrary, otherwise violative of the

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standards of Sections 4 and 5 of the Act, and unlawful." Mobil also states (Application, page 4) the Commission has adopted "a rate design and refund-forgiveness program unsupported by required findings of fact, unsupported by substantial evidence, and without required opportunity to be heard thereon, and has thereby denied Mobil due process of law."

Mobil has been given full opportunity to present its legal arguments on this question, and has done so in its application for rehearing and reconsideration. It has not alleged any new facts or the existence of any additional evidence which would require an evidentiary hearing. As to the argument that the evidence and findings of fact are insufficient to support the action of the Commission, it is our view that the facts are well established and the evidence ample. It is well established, and we so find, that demand for additional gas reserves, both nationally and in the Other Southwest Area, greatly exceeds the presently available supply. It is well established, and we so find, that the interstate market in the Other Southwest Area could readily absorb substantial additional supplies of gas if they were available. We are constantly called upon to deal with gas curtailment programs arising from the shortage of avail-

able supplies. In an increasing number of cases we must consider the question whether facilities for new or expanded service may be certificated in view of the shortage of supplies. Under these circumstances we find that incentives to seek and develop additional gas supplies and to dedicate them to the interstate market are necessary, desirable and in the public interest. We find, therefore, that an incentive other than a higher level of area prices will tend to provide an additional stimulus which area price levels alone can not in this area. The producer who dedicates additional reserves in this area to interstate commerce is assured that he will receive the incentive of a refund credit. It is obvious that a refund provision does provide an incentive to producers with refund obligations to explore, develop and dedicate additional reserves. The incentive will not operate unless additional gas is obtained, so if additional gas is not dedicated the incentive will have no effect upon refunds. If gas is obtained

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as a result of the incentive proposed, it will have proven well worthwhile in alleviating the current shortage and in reducing the unit operating cost of the interstate pipeline from this area. (See *Texas Gulf Coast Area Rate Proceeding*, Opinion No. 595, p. 42, paragraph 118, modified and clarified in other respects, Opinion No. 595-A, —— FPC —— (1971)).

PSCNY argues that "there has been no showing that the alleged benefit to the interstate consumer, which the Commission recognizes may not be great in this area, approximates the $5,000,000 in additional revenues they would be required to pay." This misstates the effect of the provision.

It is our view, and we so find, that there is a benefit to the consuming public in obtaining additional gas reserves at a time of gas shortage.

FURTHER FINDINGS AND ORDERS

The Commission finds:

The assignments of error and grounds for rehearing or reconsideration set forth in the applications for rehearing present no facts or legal principles which would require any change in or modification of the Commission's Opinion No. 607-A and its acompanying order.

The Commission, acting pursuant to Section 4, 5 and 16 of the Natural Gas Act (52 Stat. 822, as amended, 823, 830, 15 U.S.C. 717c, 717d, 717o) and Sections 553, 556, and 557 of Title 5 of the United States Code (the Administrative Procedure Act, 60 Stat. 238, 239, 241, 242, as codified September 6, 1966 by 80 Stat. 383, 384, 386, 387) orders:

The applications for rehearing and for reconsideration of Opinion No. 607-A, or of Opinion No. 607 as modified by Opinion No. 607-A, are denied.

By the Commission: Commissioner Moody not participating.

[SEAL]

KENNETH F. PLUMB,
Secretary.